AUSTRALIAN ENERGY COUNCIL

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Submitted by email to: info@esb.org.au

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AEC Response to ACCC Recommendation 1 Consultation Paper

The Australian Energy Council (AEC) welcomes the opportunity to make a submission to the Energy Security Board's (ESB) consultation on the ACCC's Retail Electricity Pricing Inquiry (REPI) Recommendation 1: 20% generation ownership cap per region.

The AEC is the industry body representing 23 electricity and downstream natural gas businesses operating in the competitive wholesale and retail energy markets. These businesses collectively generate the overwhelming majority of electricity in Australia and sell gas and electricity to over 10 million homes and businesses.

Introduction

The REPI Recommendation 1 was that the National Electricity Law (NEL) should be amended to prevent any acquisition or other arrangement (other than investment in new capacity) that would result in a market participant owning, or controlling dispatch of, more than 20 per cent of generation capacity in any NEM region or across the NEM as a whole. The ESB has been tasked with providing the COAG Energy Council with advice on this proposed NEL change.

The AEC does not consider that the case has been made to introduce a specific anti-trust mechanism into the NEL, and that such matters are better:

- addressed in the Competition and Consumer Act (CCA);
- expressed, as they are presently in CCA s50, in a qualitative form referring to the substance of the matter; and
- should apply equally to all industries active in Australia.

The AEC recognises that the ACCC formed a different view during the REPI, and the ESB is tasked here with providing advice on their recommendation. The AEC considers it is open to the ESB to advise the COAG Energy Council that no case has been made to embed in the NEL a quantitative restriction on generation acquisitions or other arrangements. Our argument as to why there is no case for such a change is set out below. To the extent the ESB is minded to propose a solution that is consistent with the recommendation or seeks to address the concerns behind the recommendation, our proposed direction path is also described below.

This submission does not directly respond to the questions in the consultation paper, such as whether there is a more appropriate figure than 20 per cent. However the discussion below explains why there is no right answer to any of these questions, and instead challenges their premise.

Market Structure in light of Industry Change

The REPI appears to have formed its views very much from the existing market structure, and in particular the ACCC's inability to inhibit the acquisition of Macquarie Generation by AGL in 2014. In 2018, the AEC commissioned a report by respected energy market economist, Rajat Sood, into the NEM's market structure in light of technology and policy developments.

Sood concluded that the dramatic shifts underway in the NEM, particularly in the application of new technologies, will entirely change the assumed competition paradigm behind observations such as those presented in the REPI. In particular the future will be characterised by, *inter alia*:

- generation technologies that have much lower scale efficiencies and are more quickly constructed than have been the case in the past, hence presenting much more realistic threats of small, fast entry;
- distributed energy technologies that create customer demand elasticity to short-term prices, inhibiting the power of any firm to set spot prices; and
- much deeper national transmission links which will undermine the market's existing regional construct.

The analysis behind REPI Recommendation 1 was backward looking, yet all credible industry forecasts, such as AEMO's Integrated System Plan amongst others, forecasts a fundamentally different industry in future with characteristics such as those above. Thus it would not be appropriate to apply a long-lasting anti-trust mechanism which was developed for a different paradigm than its application.

Sood's report is attached to this submission.

National Electricity Law

The NEL and its associated Rules are intended to provide the market upon which competition can operate, however the NEL was never intended to directly regulate competition. This was a conscious decision as evidenced by the following:

- The National Electricity Rules Clause 3.1.4(b) says in relation to the Market Rules, "This Chapter is not intended to regulate anti-competitive behaviour by Market Participants which, as in all other markets, is subject to the relevant provisions of the *Competition and Consumer Act 2010* (Cth) and the Competition Codes of participating jurisdictions".
- When introducing the New Electricity Law, forming the structure of the current NEL in 2005, the Honourable P. Holloway (Minister for Industry and Trade) addressed concerns raised by other members in the South Australian Legislative Council in the parliamentary debate:

  > "*At no stage has it ever been contemplated that any body other than the ACCC would undertake the role of competition regulation under the Trade Practices Act (now CCA). That said, it follows that the provisions of section 46 of the Trade Practices Act will continue to apply to the NEM and its industry participants."*[1]

- In the Australian Energy Market Commission's (AEMC) *Bidding in Good Faith Options Paper* it stated, "Market Participants are subject to the CCA, and the CCA prohibits most forms of anti-competitive behaviour. There is therefore no need to replicate the provisions of the CCA in the NER."[2]

Anti-trust has always been considered a matter for dedicated competition law, rather than industry codes and law. Incorporating competition law into the NEL has the following detriments:

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[1] Available at https://www.aemc.gov.au/sites/default/files/content/1befd7c9-4b33-4ace-a715-60ce2d34c810/NGF-letter-to-AEMC.pdf
[2] AEMC, *Bidding in Good Faith Options Paper*, 18 December 2014, p.45

- It confuses the purpose of the NEL, which presently aims to provide the platform upon which a market with a presumed competitive structure can achieve the most efficient outcomes.

- By drawing the NEL into the area of regulating competition, it can encourage rule-making to be distorted away from an efficient ideal in order to manage some perceived competition issues at the time of the rule making.

- By spreading the anti-trust regulation across multiple instruments, it confuses legislative processes and compliance.

- It does not have the benefit of the economy-wide considerations and rigour that would be applied to any amendment to the CCA.

- The NEL's sanctions regime is derived from its history as an industry code, triggered by specific technical events upon registered participants. It is not designed to constrain the acquisition nor force the disposal of assets and it is not clear how it would approach this.

- The NEL's registration arrangements are assumed to be voluntary with no expectation nor ability for AEMO as registrar to assess a registering company's affiliations.

- The NEL is a complex state instrument, applying to a subset of jurisdictions. Meanwhile the CCA is a Commonwealth act with a dedicated Commonwealth regulator. This confuses the role of Commonwealth versus state legislation in regulating Australian competition and may raise constitutional questions. The situation is further confused by the proposed 20% test incorporating elements of inter-state trade.

- The REPI gave two examples of industry specific Australian anti-trust legislation: airports and broadcasting, each a constitutional responsibility of the Commonwealth. Broadcasting cross ownership restrictions evidences some of the difficulties that a NEL hard cap is likely to face. That industry now bears little resemblance to the pre-internet era during which the restrictions were devised. Its constraints upon traditional media may even be counter-productively hastening the dominance of large internet-based media companies. In contrast, the CCA's s50 qualitative assessment is able to keep with the changing environment.

- There may be conflict with the application of other rules such as the three year notice of closure rule change,[3] and hence unintended consequences, such as the departure of generators from the market.

Anti-trust metrics

The existing CCA s50 test "substantially lessening competition" is an intentionally qualitative and generalised statement. Such an approach has major advantages over a hard metric:

- A hard cap will always be arbitrary, and the 20% figure is no exception. A qualitative approach allows regulators and courts to consider the substantive matters that affect the specific merger at the time; some cases involving higher shares are benign, whilst competition concerns may arise in other cases with lower shares.

- Qualitative approaches allow anti-trust practice to adapt with changes to the industry over time. This is particularly pertinent with the dramatic changes foreshadowed in Sood's report. At the same time, progressive decisions forms a body of case law, guiding firms in their contemplation of business structure.

- The existence of a hard cap for the electricity industry will necessarily weaken the role of CCA s50. Intentionally or not, the 20% rule will become an assumed guideline for the industry, regulators and courts to assume for all s50 decisions. Even in cases where the 20% has no logical relevance, it will

[3] Available at https://www.aemc.gov.au/rule-changes/generator-three-year-notice-closure

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become the starting point of argument and a burden of proof will be placed on those who wish to vary from it.

- Hard metrics invite firms to inefficiently structure their businesses to meet an arbitrary number. In contrast, with a qualitative regulation, firms will contemplate how the regulator is going to consider a merger against the synergistic benefits of the merger. The firm will put most regulatory effort into mergers that create for it the strongest efficiencies, efficiencies that increase its chances of success against s50. It will not bother pursuing mergers of marginal benefit. This is the most efficient industry outcome. With a hard cap, the business will instead pursue only those that just avoid the hurdle, whether or not it delivers significant value.

- The generalised nature of s50 encourages exploration of bespoke undertakings that achieve a win for both competition and the firm's objectives. The regime encourages such win-wins to be negotiated out of court. In contrast a firm cap can only have a yes or no outcome.

- The proposed hard cap disallows the consideration of efficiencies that may come about through a merger and ultimately benefit consumers. For example, with power stations with large relative unit sizes, owners tend to withhold one unit's capacity from the contract market for risk management purposes. Sometimes combining ownership with another power station can release more total capacity to the contract market than two separate owners. S50 allows such efficiencies to be traded off against any competitive detriment that might result.

- Definitions relying on "nameplate capacity" import false precision, create anomalies and invite gaming. This is explained in more detail in the section below.

- The cap is to apply to NEM regions. The regional structure has its genesis in dispatch and pricing accuracy and was never intended to group competitors. The abolished Snowy region shows how a small region may exist for pricing efficiency reasons without creating intra-regional competition concerns. It is likely that, in order to attempt to improve pricing accuracy, regional structures will evolve over time, and it would be foolish for such subdivisions to introduce new competition requirements. It would be very disappointing if this competition rule unintentionally created a new barrier to evolving the regional structure or was used to justify the lessening of dispatch efficiency through grouping of regions in order to lessen the impact of an ownership cap. Furthermore, the AEMC is presently studying a concept of "dynamic regional pricing",[4] which, if implemented, would remove all significance of regional structure upon generator settlements.

- By relying on a hard cap, the rule prohibits mergers that are clearly in the interests of the public. Even with willing sellers, there is not always a pool of available buyers. Consider for example the Redbank and Anglesea Power stations. It is hard to see how a plant closure could be better for competition than a merger. The transfer of Tamar Valley Power Station to Hydro Tasmania in 2013 was a key part of the State Government's policy to secure supply. Competition was never a relevant matter as Tasmanian generation is subject to separate regulation. Whilst s50 was able to recognise these circumstances, the proposed 20% cap would clearly be breached.

- The cap's impact upon businesses' growth will depend upon the sequence of that growth. Consider a firm growing through both acquisition and new investment. If the investments precede the acquisitions, the cap will have a quite different impact than vice-versa, even if the ultimate firm size is the same.

If the ACCC feels it has been frustrated in its attempts to apply CCA s50, because in practice the wording presents too high a bar, then the appropriate response is not to replace it with hard metrics that introduce the difficulties listed above, but to focus upon the wording of the general condition within the CCA.

Difficulties with relying upon nameplate capacity

[4] https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

Nameplate capacity is often mistakenly assumed to be a precise measurement of the significance of a generator in the market. In fact, the opposite is the case and there are numerous challenges with relying upon this metric in any critical decision making:

- Capacity is not a precise concept for generation plant. The NEM's existing registered capacities are self-declared and frequently adjusted by generators without regulatory oversight.[5] This is not problematic as registered capacity has no financial consequence in the energy-only NEM, however a hard merger cap will create a distortionary incentive on this self-declaration which will in turn cause difficulties for AEMO's forecasting processes.

- The REPI recommendation proposed different approaches to "thermal/dispatchable" plants to other technologies. However there is no clear definition of what is a "dispatchable" plant. Any effort to introduce one will face considerable conceptual challenges with technologies such as run-of-river hydro and energy-limited storage, amongst others.

- The REPI recommendation incorporates no consideration of distributed resources, such as demand-response and batteries that are developing with the ability for central control. These would appear to be at least as "dispatchable" as thermal plant.

- There is no available equivalent to "nameplate capacity" with respect to interconnectors. Instead the constraint upon interconnectors is an outcome of the real-time dispatch process, taking into account the capacity of all elements in the complex network, the location of generation and their bidding behaviours at any one time.

- The REPI recommended that the approach should "account for a market participant's capacity that is available in adjoining regions, adjusted for interconnector limits across regions". The intention is to account for a firm's ability to influence imports into a region, but it is unclear how this could be achieved in practice. An interconnector introduces additional competition into a region through the outcome of the dispatch process upon generators in the region(s) at the other end of the interconnector. There is no way to mathematically predict, ahead of dispatch time, the significance of a firms' remote assets upon the competitive dynamics of a particular region. Any approach that involves calculating a firm's "capacity share of an interconnector" is therefore meaningless.

- The ESB paper has used as an example "…establish adjustment factors based on the methodologies used by AEMO in its forecasting processes to de-rate different technologies and treatment of interconnectors". There appears to be a misunderstanding behind this example. AEMO no longer uses deterministic "de-rating" in its forecasting and instead relies on probabilistic analysis where plant behaviour is directly simulated.[6] This move away from deterministic capacity calculations was forced upon AEMO by the same difficulties in realistically accounting for capacity, including interconnector capacity, that would be experienced in calculating any ownership cap.[7]

    - On the other hand, previous considerations of transactions under s50 have relied heavily upon probabilistic market simulation, which does not require these difficult de-rating approximations.

- A number of technical matters, which are extremely difficult to fix in advance, further challenge the basis of a hard capacity cap:

    - Transmission congestion affects the reliable output of many generators. It is quite rational for firms to invest in additional capacity where they perceive a real risk of the output being limited.

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[5] Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists
[6] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Data/MMS/2018/MT_PASA_Process_Description.pdf
[7] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Data/MMS/2016/EY-MTPASA-Final-Report-2016-11-23C.pdf

- ○ Most interconnector constraints incorporate many generator terms. This means the operation of individual generators themselves impact upon interconnectors in complex ways.

- ○ Loss factors directly affect the equivalent value of capacity within a region. Capacity can be adjusted for current loss factors, but these change year on year.

- ○ Fuel constraints affect some thermal plants. It can be more efficient to invest in more generation capacity and rely on diversity rather than investing in additional fuel assurance in the one generator.

- ○ Start-up time and ramping speed varies considerably between generators. This in turn has significant impact on its competitive significance, and will become even more important when five minute settlement is introduced in 2021.

Proposed way forward for the ESB

Regardless of the merits of our concerns about Recommendation 1, the AEC recognises that the REPI recommended it, which, should the ESB accept our views, presents a dilemma. The AEC suggests the ESB exploring other paths, such as:

- Feeding back to the COAG Energy Council a view that the concerns behind Recommendation 1 are better achieved by focussing upon the CCA rather than the NEL. The ESB could present its observations on whether and why the s50 is not assuaging ACCC concerns in the electricity industry. It would then become the Commonwealth's prerogative to amend the CCA appropriately.

- Not proposing a NEL adjustment, but instead preparing a position statement with the conclusions of this work being about the issues that lead to Recommendation 1 and how these concerns relate to s50 decisions. The statement would not propose any hard metrics, but could discuss how, in the ESB's view, taking account of the REPI recommendation, NEM transactions might lead to a substantial lessening of competition. Coming from the ESB, it would presumably carry considerable weight in CCA interpretation.

- Recommending that the Australian Energy Regulator (AER), as the body that is most closely aware of contemporary NEM circumstances, provide expert independent input into all s50 decisions.

Any questions about our submission should be addressed ben.skinner@energycouncil.com.au or by telephone on (03) 9205 3116.

Yours sincerely,

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NEM STRUCTURE IN LIGHT OF TECHNOLOGY AND POLICY CHANGES

REPORT FOR THE AUSTRALIAN ENERGY COUNCIL
PREPARED BY RAJAT SOOD, FRONTIER ECONOMICS

13 DECEMBER 2018

CONTENTS

EXECUTIVE SUMMARY

Policy-makers and regulators have recently raised concerns about high prices in Australia's National Electricity Market (NEM). This report discusses technological, policy and structural developments in the energy sector that are underway or are likely to take place over the next decade and considers their implications for the likely future structure, conduct and performance of the NEM. In particular, this report considers whether changes in technology, market architecture and the supporting infrastructure could over time address concerns that policy-makers and regulators have raised about wholesale market bidding, contracting, vertical integration and pricing outcomes.

The NEM has traditionally exhibited a combination of characteristics that differentiate it from many other markets in the economy. These characteristics are:

- Generating plant has tended to be large and expensive to build, which has made it hard for smaller players to participate;
- Electricity demand is highly unresponsive to real-time prices; and
- To maintain a secure power system, electricity supply needs to equal demand at all times.

Taken together, these features imply that wholesale prices can be very volatile depending on physical supply/demand conditions, which in turn draws greater scrutiny on the size of each player's portfolio.

These features also mean that when new plant enter the system or retiring plant leave, average prices can suddenly collapse or jump, respectively, reflecting the marked implications of changes in the industry supply-demand balance. Customers have recently experienced the latter phenomenon following the exit of the Northern and Hazelwood power stations – in both cases, wholesale prices went from very low levels to well above the long run average in the space of weeks or months. Similar outcomes could occur again in future if other large fossil-fuel generators were to close as renewable plant continue to enter the NEM in response to Commonwealth and State renewable energy targets (RETs). The price impact of large plant exits is illustrated in a stylised manner in **Figure 1** below.

Given the essential nature of electricity to citizens and businesses in the modern economy, these types of abrupt shifts naturally cause public consternation and draw the attention of policy-makers. Many of the relatively interventionist measures proposed to date are directed at addressing what policy-makers perceive to be competition problems that stem from the current environment.

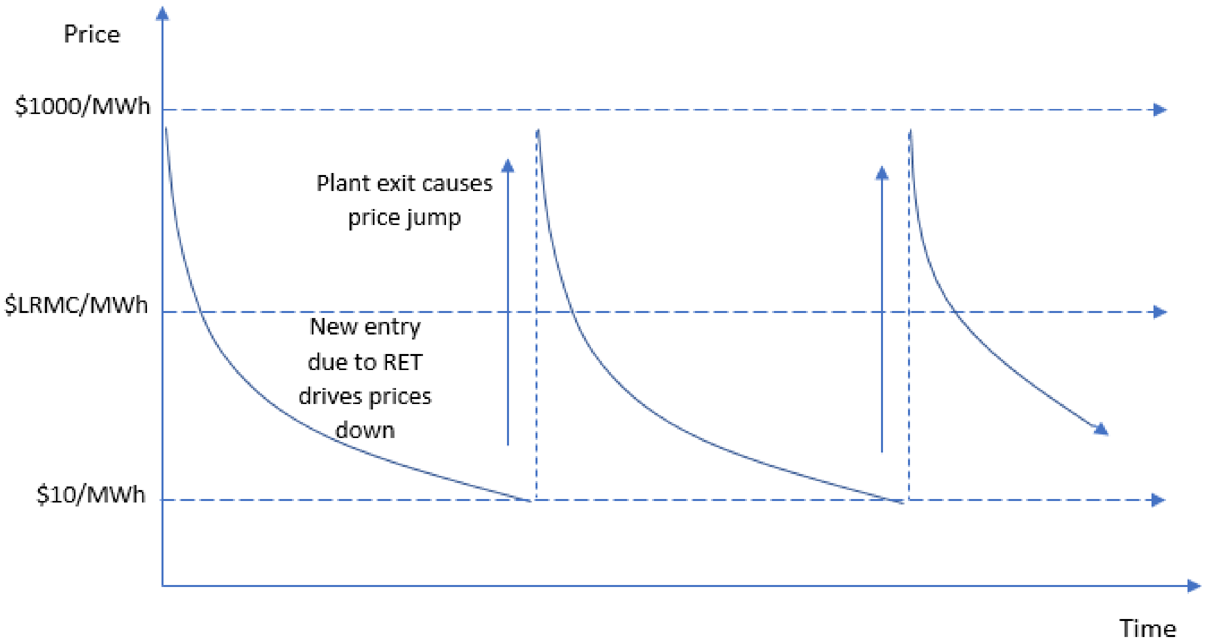
However, recent and upcoming changes to electricity generation and storage technology, market architecture and supporting infrastructure are likely to mitigate not only these medium-term price cycles in the NEM, but also the scope for generators to instigate short-term price spikes – thereby overcoming much of the impetus for the kinds of interventions that have been put forward. The types of changes that have already been forthcoming or are likely to occur over the next few years are as follows:

- The availability of renewable plant in much smaller increments and reflecting much smaller scale efficiencies than traditional generators, and the much shorter lead times for commissioning such plant. These developments will make it easier for small non-vertically-integrated retailers and business customers to sponsor the entry of new plant.
- Substantial reductions in the costs of utility-scale solar thermal plant and battery storage, in particular.
- More transmission investment across the NEM to reduce network constraints and facilitate the movement of power from 'renewable energy zones' to demand centres.

- Detailed changes to the operation of the NEM to reduce strategic bidding incentives and promote dispatchable demand response from smaller customers.
- A new obligation on generators to notify the market of their intention to exit three years in advance of doing so.
- Smarter metering and energy management systems combined with further increases in rooftop PV and distributed batteries to increase the real-time ability of demand to respond to high wholesale prices.
- The possibility of a liquefied natural gas (LNG) import terminal in the southern part of the NEM, helping to diversify fuel supplies and increase competitive discipline on existing gas suppliers.

This combination of technological, economic and policy-driven changes is likely to have a very significant effect on participant short- and longer-term decision-making and on medium-term price cycles.

Figure 1: Recent RET-driven price-cycle dynamics

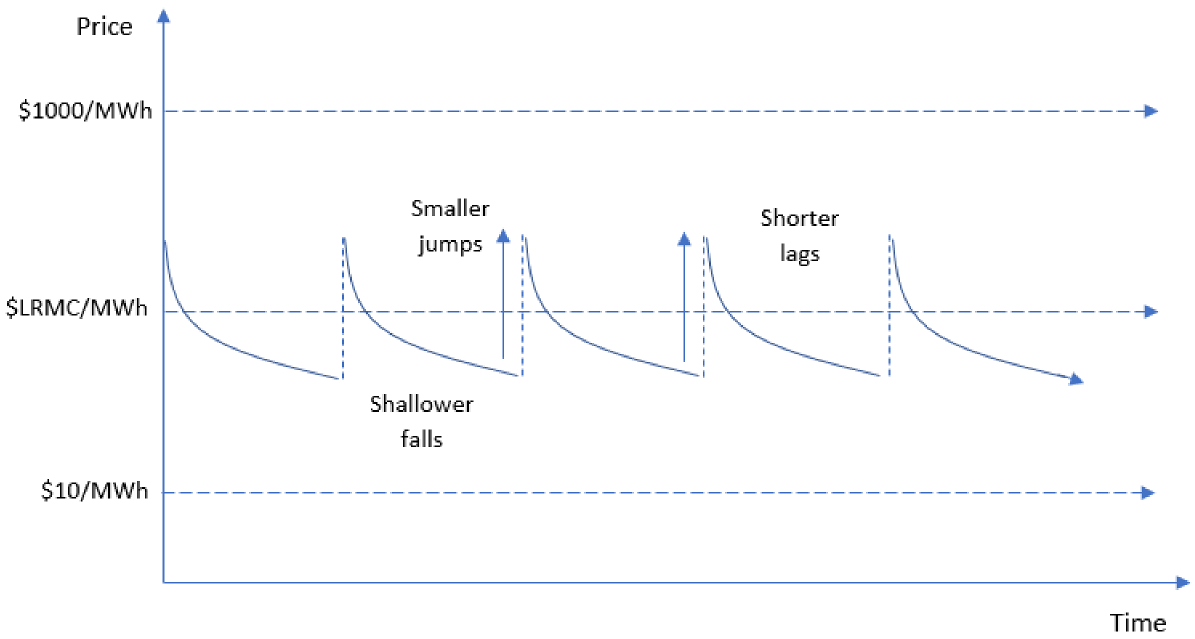


Source: Frontier Economics

As a result of the greater scope for existing and new investors to finance and develop small additions of generating plant, the abruptness and amplitude of medium-term price cycles is likely to diminish. These price cycles are likely to shift over the next decade from the familiar pattern shown in **Figure 1** towards cycles that appear more like those in **Figure 2** below.

In addition, short term price volatility is likely to reduce, as the wider adoption of battery storage and greater participation of scheduled demand response increase the ability of demand response to attenuate price spikes and other changes such as the impending move to 5-minute participant settlement and deeper transmission interconnection impose tighter discipline on participant bidding behaviour.

Figure 2: Future RET-driven price cycles in the NEM



Source: Frontier Economics

Overall, these developments are likely to offer three major benefits from the perspective of policy-makers and regulators:

- The first is that they should help smooth wholesale price volatility in both the short term and in the medium to longer term;
- The second is they should reduce the advantages of the vertically-integrated ‘gentailer’ business model; and
- The third is that they should encourage more competitive behaviour in the NEM wholesale market and thereby lead to more efficient and cost-reflective dispatch and pricing outcomes.

In this way, the analysis in this report is directly relevant to whether interventions of the type that have been proposed are likely to be worthwhile.

These developments are also broadly consistent with the satisfaction of the National Electricity Objective (NEO), although only the third is directly relevant. Reduced price volatility may or may not promote the NEO in itself, but is expected to be a consequence of behaviours that would promote the NEO – namely, more efficient participant decisions about energy usage and investment, and more cost-reflective bidding. Similarly, reduced advantages for the gentailer business model may not promote the NEO directly, but could increase competition by lowering entry barriers.

1 INTRODUCTION

This report has been prepared by Rajat Sood, consultant at Frontier Economics, for the Australian Energy Council (AEC). This report discusses the implications of technological and policy changes in the energy sector for the likely future structure, conduct and performance of Australia's National Electricity Market (NEM). The report considers whether changes in technology and energy infrastructure combined with forthcoming modifications to the NEM design could over time organically address concerns that policy-makers and regulators have raised about wholesale market bidding, contracting, vertical integration and pricing outcomes both recently as well as at various times since the commencement of the NEM. As well as helping to address policy-maker and regulator concerns, these technological and other developments should enable to market to better meet the National Electricity Objective (NEO)[1] – which is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- price, quality, safety and reliability and security of supply of electricity
- the reliability, safety and security of the national electricity system.

This report is arranged as follows:

- Chapter 2 summarises concerns raised by the Australian Competition and Consumer Commission (ACCC or Commission) in its Retail Electricity Price Inquiry (REPI) final report and subsequently by the Federal Government in its recent consultation paper on electricity price monitoring and responses.
- Chapter 3 attempts to discern the specific underlying economic features of the NEM that do not apply to most other markets and appear to have given rise to the concerns of policy-makers and regulators.
- Chapter 4 briefly summarises our literature review on recent and expected future changes in technology and outlines key policy and other expected changes to the operation of the wholesale market.
- Chapter 5 explains the implications of changes in technology, market architecture and the supporting infrastructure for the underlying drivers of policy-makers' concerns about the NEM wholesale market and how the changes are likely to lead to policy-makers' concerns dissipating over time.
- Appendix A Energy-only wholesale market operation – provides a brief explanation of how energy-only markets such as the NEM are designed to remunerate investors for their fixed and sunk costs and provide incentives for investment in an optimal mix of plant.
- Appendix B Literature review – contains the most salient findings from our literature review of historical and expected future technology changes and costs.

[1] *National Electricity Law*, section 7.

2 CONCERNS RAISED BY POLICY-MAKERS AND REGULATORS

2.1 Background

Policy-makers and regulators have recently been expressing concerns about prices in the wholesale and retail electricity markets that appear to them to be excessive. In the retail market, the primary concern appears to be that customers who are either unable or unwilling to vigilantly monitor retailer offers pay far higher tariffs than are available and that this 'loyalty tax' feeds into retailers' profits. In the wholesale market, the key concerns appear to revolve around the bidding and contracting behaviour of the large incumbent generators, including the vertically-integrated 'gentailers'. The large generators are seen as engaging in and benefitting from the exercise of some form of market power, both by increasing wholesale spot and contract prices as well as potentially by withholding the supply of hedge contracts that are regarded as a necessary input to retailing.

This report focuses on the concerns raised by policy-makers and regulators about the *wholesale market*, as well as how the wholesale market can influence the retail market through vertical integration. The report seeks to identify the underlying reasons for policy-maker and regulator concerns, and the extent to which these underlying causes are likely to be overcome or addressed by expected technological and other structural or market design changes over the next decade. I note that similar concerns have been expressed by policy-makers and regulators at various times since the commencement of the NEM. For example, in 2001, in response to a number of price spikes in the wholesale market, the then National Electricity Code Administrator made an application to the ACCC for authorisation of changes to the National Electricity Code seeking to prohibit bids that "have the purpose, or have or are likely to have the effect, of materially prejudicing the efficient, competitive or reliable operation of the market".[2]

This chapter outlines the concerns raised by the:

- ACCC in its Retail Electricity Pricing Inquiry (REPI) final report of June 2018;[3] and
- Commonwealth Government in its Electricity price monitoring and response legislative framework Consultation paper (Consultation paper) of October 2018.[4]

2.2 ACCC REPI

The ACCC's REPI raised concerns about both wholesale market concentration and vertical integration.

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[2] See NECA Code Change Panel, *Generators' bidding and rebidding strategies and their effect on prices*, Volume 1 Report, September 2001, available at: https://www.accc.gov.au/public-registers/authorisations-and-notifications-registers/authorisations-register/nec-rebidding-code-changes.

[3] ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry – Final Report*, June 2018 (ACCC REPI), available at: https://www.accc.gov.au/regulated-infrastructure/energy/electricity-supply-prices-inquiry/final-report.

[4] The Australian Government the Treasury, *Electricity price monitoring and response legislative framework, Consultation paper*, October 2018 (Consultation paper), available at: https://treasury.gov.au/consultation/c2018-t337042/.

2.2.1 Wholesale bidding

The ACCC did not find evidence of the large generators systematically engaging in output-withholding behaviour to 'spike' wholesale prices.[5] However, the report included some discussion about coal-fired generators in New South Wales and Queensland experiencing higher fuel costs in recent times and increasing their offer prices by more than the Commission considered necessary to reflect those cost increases.[6] See **Figure 3** and **Figure 4**, reproduced from chapter 3 of the REPI.

Figure 3: NSW black coal generator bidding

Figure 3.7: Weighted average quarterly NSW black coal generators' fuel costs, coal export prices, weighted average offer prices and average NSW wholesale prices, Q3 2014 to Q1 2018 ($/MWh nominal)

Source: ACCC analysis of fuel cost data provided by generators; Indexmundi; AEMO data.

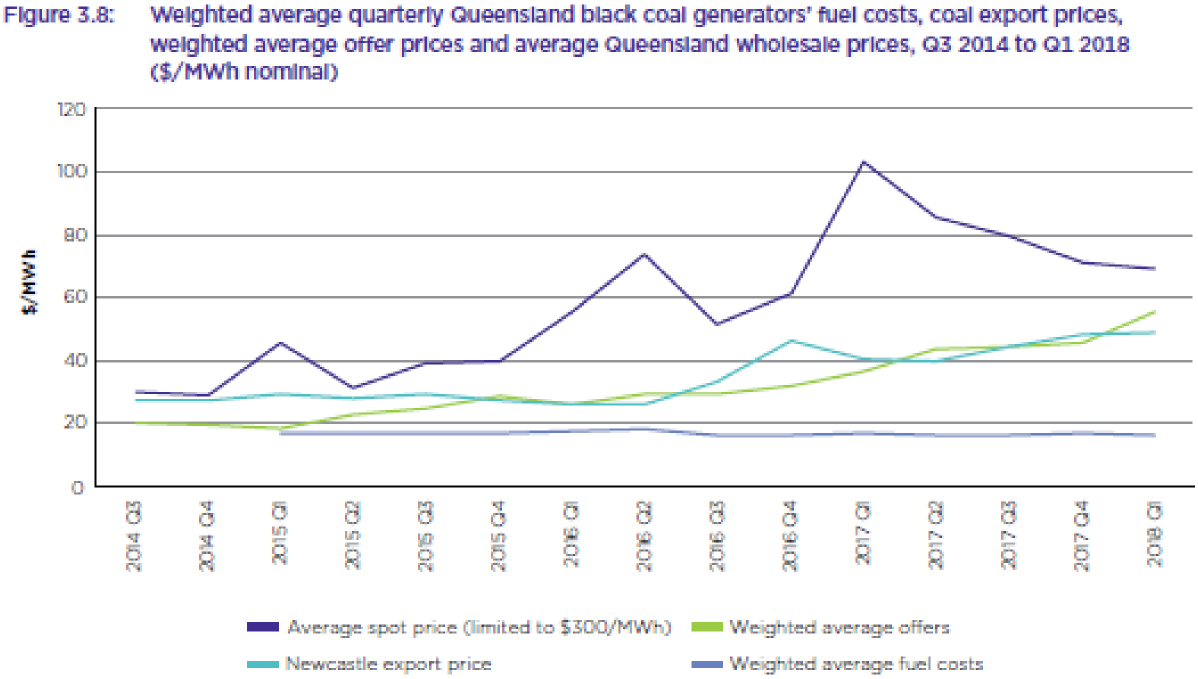
Note: Weighted average offer prices are for offers of $1–150/MWh; Newcastle FOB thermal coal prices converted to $/MWh using an appropriate calorific value and heat rate; NSW wholesale prices are the average of spot prices limited to $300/MWh.

Source: ACCC REPI, p.68.

5 The ACCC said: "[T]he key cause of higher wholesale prices is less related to discrete instances of market power being used to spike the price and more driven by a subtle and sustained 'lift' in prices that can be attributed in part to a lack of competitive constraint." See ACCC REPI, p.96.

6 It is not clear why the ACCC chose to focus on the differences between black coal generator offer prices and contract fuel costs rather than the Newcastle export price, which better reflect the opportunity cost of black coal and from which offer prices show much smaller divergences.

Figure 4: Queensland black coal generator bidding



Source: ACCC REPI, p.69.

The Commission concluded:[7]

> The ACCC considers that the overall widening between NSW and Queensland black coal generators' offer prices and their fuel costs is likely to be a product of a lack of competitive constraint and the highly concentrated market structure in Queensland.

These concerns did not extend to the bidding behaviour of gas-fired generators:[8]

> The ACCC also considered how gas generators' average offer prices related to their fuel costs. Average gas generators' offers increased from $30–50/MWh (depending on the region) in early 2015, to around $90/MWh in early 2018. In Victoria, NSW and South Australia, average offers were generally above fuel costs by $10–15/MWh in the earlier periods, however fuel costs and average offers tended to increase together and converge by late 2017.
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> Unlike black coal, the ACCC's analysis indicates that gas generators' average offers at cost-related price bands tended to increase in line with their fuel costs, which to an extent appear linked to (gas) market prices.

The REPI also highlighted instances of generator bidding behaviour and dispatch outcomes in different NEM regions before and after certain market structural changes and policy interventions as a means of demonstrating the apparent influence of these factors. For example, following the closure of the Hazelwood power station in March 2017, the ACCC commented that both AGL and Origin Energy began shifting significant capacity of their Bayswater and Eraring power stations, respectively, into higher price bands from December 2016. Both participants at least partly reversed these increases from about October 2017 onwards.[9] Similar behaviour by AGL in relation to Pelican Point had followed the closure

[7] ACCC REPI, p.69.

[8] ACCC REPI, p.71.

[9] ACCC REPI, p.77.

of the Northern power station in South Australia in May 2016. The ACCC also observed that the Queensland Government's direction to Stanwell in July 2017 to "place downward pressure on prices" appeared to show a 'stark effect' on Stanwell's bidding behaviour from around that date.

The ACCC concluded its findings on generator bidding behaviour as follows:[10]

> Following the closure of Hazelwood, the behaviour of particular NSW black coal generators appears to be a result of both increases in fuel costs (and fuel supply issues in parts of 2017) and outcomes from an environment where generators can and appear to have acted in a relatively unconstrained manner. This lack of competitive pressure is of concern to the ACCC, particularly given the critical need for a sufficient level of competition in this market to drive affordable electricity prices.
>
> The concentrated nature of the South Australian market has clearly contributed to high price outcomes in that region, particularly when supply conditions in the region have been tight. When supply has been improved, through the return of Pelican Point as well as the introduction of the Hornsdale Power Reserve, there has been downward pressure on prices in the region.
>
> In terms of the Queensland black coal generators, the ACCC considers that analysis of the available information indicates that, in the absence of the direction by the Queensland Government to place downward pressure on wholesale prices, there is very limited constraint on the bidding behaviour of Queensland's black coal generators.

In response, the ACCC made a number of recommendations in relation to the wholesale electricity market including:

- Prohibition on any acquisition or arrangement that would raise a participant's market share above or beyond 20 per cent (Recommendation 1)
- General market manipulation rule – to prevent fraudulent or misleading behaviour intended to distort or manipulate prices, mainly in the future and especially under the NEG (Recommendation 3)
- Australian Government to enter into 'low fixed-price' offtake contracts for the 'later years' of new generation projects that meet certain criteria (Recommendation 4)
- OTC contract disclosure obligation (Recommendation 6)
- Market-making obligations on vertically-integrated firms in South Australia (Recommendation 7)

The question for policy- and rule-makers of the NEM has always been whether trying to regulate what Justice French in 2003 called the exercise of 'transient market power'[11] is worth the cost. The key risk of, say, capping generator bids is that if the regulator gets it wrong and sets the cap too low, generators could choose to withhold their output altogether, potentially leading to load shedding (or blackouts). This would then require the regulator or another party to conduct an in-depth audit to establish whether the generator's reason for not offering its output into the market was genuine. This would constitute a very intrusive, laborious and error-prone process.

Ultimately, the ACCC did not recommend specific market power mitigation rules, echoing the 2013 assessment of the AEMC that such rules "would address the symptoms rather than the underlying cause of market power."[12] The ACCC instead supported structural solutions, although it did recommend a general prohibition on market manipulation in a similar form to the prohibition that applies to gas supply hubs.[13]

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10 ACCC REPI, p.87.

11 *Australian Gas Light Company v ACCC (No 3)* [2003] FCA 1525 (19 December 2003), at para 453. See: http://www.australiancompetitionlaw.org/cases/agl.html.

12 ACCC REPI, p.96.

13 ACCC REPI, pp.96-98.

2.2.2 Vertical integration

Chapter 5 of the REPI focused on concerns surrounding wholesale contracting trading in the NEM and the effect of vertical integration. The ACCC highlighted concerns that:

- Vertical integration provides gentailers with cheaper access to wholesale power than smaller retailers; and
- Vertical integration has reduced contract liquidity and lessened the ability of (standalone) participants to effectively manage their risk.

While recognising the efficiency benefits of vertical integration and the variety of ways in which 'liquidity' can be defined and has changed over time, the ACCC nonetheless expressed concern about the prospects of standalone retailers.[14]

The ACCC also sought and examined 'transfer prices' for gentailers – the prices that gentailers effectively price wholesale energy to their own retail arms – and found that:[15]

> The majority of vertically integrated businesses calculate a transfer price based on what they could sell the same electricity for in contracts with third parties. In an economic sense, the retail arms of vertically integrated businesses are paying the 'opportunity cost' of the business's generation capacity. The retailer will therefore be incurring a wholesale electricity cost comparable to a standalone retailer contracting through the market. In these circumstances, the economic benefits of vertical integration are largely accruing to the wholesale arm of the business.

I make three observations on this comment. First, setting transfer prices based on opportunity cost suggests that gentailers are treating standalone retailers on an equal basis to their own retail arms and not seeking to foreclose on rivals. Second, if one were to focus on competition as a process rather than as a situation, one would presumably seek to encourage other participants to make efficiency-enhancing changes (such as vertical integration) so as to promote competition between a larger number of more efficient competitors and raise the likelihood that those efficiencies will be sustainably passed on to consumers through lower retail prices. Third, suggesting that gentailers should pass on a greater share of the efficiency benefits from vertical integration to their own retail customers than to standalone retailers seems inconsistent with recommendations aimed at increasing the viability of the standalone retailer business model.

2.3 Commonwealth Government Consultation Paper

The Commonwealth Government's recent Consultation paper builds on the Government's announcement of 20 August 2018 that it would task the ACCC with, *inter alia*, monitoring wholesale bidding and contract market liquidity in the NEM and provide for enforcement remedies. The list of potential remedies included imposing wholesale contract market-making obligations beyond South Australia and ordering asset or business divestiture.[16]

The Consultation paper seeks comment on how 'prohibited conduct' ought to be characterised in wholesale bidding and contracting. The proposed prohibition in relation to wholesale bidding and conduct is stated as follows:[17]

14 ACCC REPI, pp.111-114.

15 ACCC REPI, p.125.

16 Consultation paper, p.2.

17 Consultation paper, p.4.

> An electricity generator must not, when making a bid or offer to dispatch electricity, act fraudulently, dishonestly or in bad faith with the purpose of distorting or manipulating prices.

The Consultation paper goes on to describe the objective of the prohibition and seek feedback on two hypothetical examples:

> The objective of this limb is to prevent conduct in the wholesale spot market (in the case of the NEM) or other form of wholesale market (outside the NEM) which is anti-competitive and can lead to an increase in prices which flows through to end consumers. The relevant conduct could involve bidding, or could involve non-bidding behaviour, such as a decision to supply or withhold supply.
>
> The Government is considering how best to distinguish between behaviour which takes advantage of periods of high prices (which, over time, should be a signal to investors) and behaviour which seeks to manipulate or distort prices in a way not intended by the design of the relevant wholesale market.
>
> Stakeholder feedback is sought on the hypothetical example below, including under what circumstances of this sort of conduct should or should not be captured by a prohibition:
>
> • Generator A schedules discretionary maintenance on a power plant to occur during a peak period in order to increase the market price, and increase the revenue received by the other power plants owned by Generator A.
>
> Another hypothetical example that may represent conduct that could be prohibited is where:
>
> • Gentailer A continually bids in significant capacity at a low price in times of relatively low demand incurring significant losses in doing so for a sustained period of time; and
>
> • Gentailer A's purpose is to ensure that a Gentailer B (a rival), which cannot incur the same losses and must bid at a price sufficient to cover its costs, is unable to be dispatched and is driven from the market.
>
> This limb is not intended to interfere with the design and operation of the relevant wholesale market. For example, the NEM wholesale spot market permits rebidding in good faith as it can allow market participants to respond to changing market conditions. Similarly, transient instances of market power can act as a market signal for more investment, stimulating competition.

2.4 Implications for the NEO

One overarching interpretation of the competition concerns expressed in the REPI and the Government's Consultation paper is that even though new generation entry has occurred in the past in response to high wholesale prices, existing generators and gentailers can have and exercise excessive market power, such that prices are higher than they would be otherwise.

To the extent these concerns are supported by recent market outcomes, they would similarly suggest that the NEM is failing to satisfy the NEO. As noted above, the NEO refers to the promotion of efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- price, quality, safety and reliability and security of supply of electricity
- the reliability, safety and security of the national electricity system

If participants operating in the wholesale market wield excessive market power, then it is unlikely that investment in the NEM will be efficient, or that consumers face prices that reflect the lowest sustainable costs of delivering reliable and secure power.

The subsequent chapters explore whether, leaving aside the merit of these concerns, technology and other changes over the next decade are likely to address the underlying drivers of these concerns, and in so doing, help the NEM to better satisfy the NEO.

3 KEY FEATURES OF THE NEM AND THEIR IMPLICATIONS

This chapter of the report attempts to discern the underlying economic features of the NEM that differentiate it from textbook models of competitive markets and many real-world markets operating in the economy. In my view, it is the outworkings of these features that have likely contributed to the policy-maker and regulatory concerns discussed in the previous chapter. The discussion in this chapter will provide a suitable context for analysing the implications of emerging and future changes to electricity technology, policy and structure for the future prevalence of the issues that have raised concerns about the market.

3.1 Nature of generation infrastructure

Electricity generating plant has traditionally exhibited a range of features that differentiate it from the supply-side characteristics of many other markets:

- Generators tend to have relatively low operating or variable costs[18] and relatively high fixed costs that are typically largely unavoidable or 'sunk' once an investment has been made.
- Generation plant has traditionally exhibited strong economies of scale, in that the average total cost of output from a given technology tends to fall (in declining order of magnitude):
  - As unit capacity size increases;
  - As the number of units in a power station increases; and
  - As the number of power stations in a portfolio increases.
- Generation plant has traditionally exhibited discreteness or 'lumpiness' of investment options, in that it has only been possible to make investments in certain minimum increments.
- The development of new generating plant has generally involved long lead times. Like other forms of large-scale infrastructure, such as transport and mining infrastructure, it takes considerable time for proponents to obtain planning and environmental consents, secure project financing, and undertake site preparation, development and commissioning.

3.2 Energy-only market design

The NEM is one of the relatively few 'energy-only' wholesale electricity markets around the world. As discussed in Appendix A, an energy-only market is one where investors in electricity supply assets are remunerated solely through the supply of power to the wholesale market at prevailing spot prices and voluntary derivative contracts settled against spot price outcomes. Unlike many markets elsewhere, the NEM does not incorporate a separate capacity market or 'mechanism' that provides investors with a

[18] In this report, the operating or variable cost of production of a generator is assumed to be a single number that excludes start-up costs and any dispatch inflexibilities. This is often referred to in the industry as a generator's short-run marginal cost (SRMC) of production.

separate stream of revenue to help recover the fixed and sunk costs of their plant. There are good reasons to expect an energy-only market to deliver more efficient outcomes than two-market designs.[19]

Nevertheless, the absence of a separate capacity mechanism in the NEM is a significant feature due to the high fixed and sunk costs that generators have traditionally exhibited. In order to recover these fixed costs in an energy-only market, the spot price must be able to at least occasionally rise above the variable cost of the plant with the highest variable costs in the market in order to enable that plant (traditionally, a gas peaking plant) to recover its fixed costs. When this happens, other generators with lower variable costs (such as coal, hydro-electric and many other renewable plant) also receive a price on their output in excess of their variable costs and a contribution towards their fixed costs. If the spot price is higher or remains high longer than necessary to enable existing generators to recover their total (fixed and operating) costs, this provides an incentive to investors to develop more plant. Conversely, if the spot price is insufficient to enable existing generators to recover their fixed costs, investors receive an incentive to not develop more plant and some existing plant may be partly or wholly shut down or 'mothballed' until conditions improve (see Part 1 of Appendix A).

The ability of new generation proponents to make investments on the basis of wholesale price signals and physically connect to the grid at minimal cost is a key design feature of the NEM, and it has the effect of placing new entrants on a similar footing to most new entrants elsewhere in the economy. That is, new entrants face relatively low barriers to investment, facilitating a timely investment response to prevailing and expected future periods of high prices. This 'open access' model of network connection is not commonplace in electricity markets elsewhere – in part, due to the conflicts that can arise between open access and the operation of separate capacity mechanisms (see Box 1).

[19] For example, see ACCC REPI, p. 41 and Wood, T., Blowers, D., and Griffiths, K. (2017). *Next Generation: the long-term future of the National Electricity Market*. Grattan Institute. (Grattan Institute Next Generation report), pp. 31, 36-37. See: https://grattan.edu.au/report/next-generation-the-long-term-future-of-the-national-electricity-market/.

Box 1: Open access

Unlike many electricity markets elsewhere, the NEM embodies an ‘open access’ philosophy to generation investment, connection and dispatch. New generators are permitted to seek connection to the transmission (or distribution) system and pay only the direct or ‘shallow’ costs of connection. Generators are not required to contribute to the cost of the existing grid or to any network expansions or extensions that they themselves do not request. The *quid pro quo* for open access is twofold. First, generators have no right to be dispatched in accordance with their position in the dispatch merit-order (which arranges participant bids and offers from lowest to highest and selects the cheapest first) and will typically have their output limited if and when applicable network constraints bind. Second, transmission network augmentation is determined in a centralised manner on the basis of an overall system cost minimisation criterion that place no value on the dispatch of individual generators *per se*.

By contrast, the Western Australian wholesale electricity market and most markets in the United States do not allow generators to connect without meeting various technical requirements and paying ‘deep’ augmentation costs. In these markets, generators seeking connection need to wait for the system operator to perform power flow analysis to ascertain the effect of the new generator on transmission constraints. This leads to a connection ‘queue’ being formed, which – combined with higher connection charges – imposes considerable delays and costs on new entry.

Part of the reason for the connection and queuing policies adopted in such markets is the role of separate capacity mechanisms. If the system operator is relying on a specific generator to be dispatched at peak times to meet demand, the system operator needs to be confident that the network will not constrain the output of that generator under peak loading conditions. This particular issue does not arise in the NEM because generators are not paid for their output unless and until they are dispatched, and transmission planning is undertaken on the basis of ensuring that sufficient energy will be available – from any generator anywhere across the NEM – to meet demand across the system to the extent necessary to satisfy the NEM reliability standard (see below).

3.3 Highly inelastic demand and the need for a MPC

Another key feature of the NEM and most other electricity markets to date has been the highly unresponsive or ‘inelastic’ nature of real-time electricity demand. Very few electricity customers participate directly in the wholesale market, although some have arrangements with retailers to curtail demand at times of high spot prices.[20] Most customers face retail prices that tend to involve flat usage-based charges. Even when customers face time- or demand-based tariffs, the applicable rates typically do not change in line with prevailing spot market outcomes. Yet the secure operation of a power system requires, *inter alia*, the maintenance of a stable system frequency, which in turn requires electricity supply to precisely equal demand at all times. Indeed, if there is insufficient supply to meet demand for even a few moments, there may be no price at which the market will clear. In these circumstances of ‘market failure’, the market and system operator will be required to shed load involuntarily and set a

[20] For example, AGL has a commercial agreement in place with the Tomago smelter that gives AGL flexibility to manage its customer load during plant outages in exchange for Tomago receiving commercial benefits. See: https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2017/february/agl-and-tomago-agreement-in-place-to-curtail-electricity.

price for the remaining transactions that are able to take place. For these reasons, the NEM incorporates a market price cap (the 'MPC', formerly the 'Value of Lost Load' or 'VoLL'), at which the spot price is set if supply cannot meet demand. The MPC is presently $14,500/MWh, which is well above the operating costs of any plant in the NEM.

The MPC is set at a level designed to ensure that generators – particularly peaking generators – are able to recover both their variable and fixed costs over those short periods when supply is insufficient or barely sufficient to meet demand. This is designed to encourage enough generation investment to ensure that periods of involuntary load shedding are relatively rare. Specifically, the NEM reliability standard is a maximum level of unserved energy (USE) in a region of 0.002 per cent of the total electricity demanded in that region for a given financial year.[21] The higher the MPC is set, the more generation and demand response is likely to be viable and hence the less involuntary unserved energy could be expected to result. In order to achieve this objective, the MPC is reviewed by the AEMC Reliability Panel every four years.

In equilibrium, an energy-only market in which participants behave in a price-taking (highly competitive) manner should not only yield levels of unserved energy and installed generation capacity consistent with meeting the NEM reliability standard at least cost, it should also produce an efficient technology mix of plant (see Part 2 of Appendix A).

3.4 Pricing and structural implications of NEM features

The unique features of the NEM as an energy-only electricity market have hitherto differentiated it from most other markets in the economy in relation to its implications for both pricing outcomes (in the short and longer terms)[22] and structural (contracting and integration) outcomes.

3.4.1 Short term pricing implications

In the very short term, even small deviations from pure price-taking conditions can result in large (transient) price spikes. Under pure price-taking, the wholesale spot price should remain relatively low (at or below the variable costs of peaking plant) unless load shedding is occurring. However, at times of very high market demand, if even one or a small number of generators refrain from offering all of their available output or raise their offer prices towards the MPC, the spot price may spike several orders of magnitude above pure price-taking levels. This is a point frequently made by the Australian Energy Regulator (AER) in its reports of conditions when NEM spot prices exceed $5,000/MWh.[23]

This extreme sensitivity of wholesale prices to supply and demand is a phenomenon that is not widely observed in any other substantial market in the economy. In general, the ability and incentive for a

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21 See: https://www.aemc.gov.au/energy-system/electricity/electricity-system/reliability.

22 'Longer term' here refers to a period of months or years, which may not be sufficient for traditional forms of supply-side capacity to be augmented or commissioned. This differs from the economic concept of the 'long run', in which all inputs are flexible.

23 For example, in relation to high prices in Victoria and South Australia on 19 January 2018, the AER said: "On 19 January maximum temperatures in Melbourne and Adelaide exceeded 40°C, leading to high demand for electricity and forecast high prices. While demand for electricity was high in both the South Australian and Victorian regions, it was not near record levels. In South Australia the spot price reached $11 864/MWh at 2.30 pm, $13 408/MWh at 3 pm, $5413/MWh at 5 pm and $5332/MWh at 6 pm. The spot price exceeded $5000/MWh only once in Victoria, reaching $10 152/MWh at 2.30 pm. The vast majority of capacity in both regions was priced in very low price bands, a small amount in very high price bands and almost no mid-priced capacity. As a result, small increases in demand at the top end of low priced capacity had the potential to lead to high prices. This was essentially the major contributing factor behind the high price outcomes." See AER, *Electricity spot prices above $5000/MWh, Victoria and South Australia, 19 January 2018*, 20 March 2018, available at: https://www.aer.gov.au/wholesale-markets/market-performance/prices-above-5000-mwh-19-january-2018-vic-and-sa.

generator to strategically withhold potential output increases with the size of the participant's portfolio, as the size of the revenue 'payoff' from higher prices increases.

Other electricity market designers have responded to the risk of this type of behaviour by imposing bidding rules or caps of one form or another. However, Australian designers have long resisted these types of measures for several reasons:[24]

- Bid-capping rules are intrusive and complicated to design and apply, and raise the risk that they could deter investment if set too low.
- Many of the markets in which these rules are imposed have two-market designs, such that the risk of deterring investment is mitigated through the returns available from a separate capacity market.
- If barriers to new generation entry are relatively low, then new entrants will respond to higher prices by investing sooner and driving prices down.
- Structural solutions – namely, horizontal disaggregation – are preferable to behavioural conditions. This view was restated by the ACCC in the REPI (see section 2.2.1 above).
- Since NEM start, market designers have been hopeful that increased demand-side response could mitigate generators incentives to engage in non-price-taking behaviour in the energy-only NEM.

Regarding the last of these points, the ACCC made the following comments in its 1997 National Electricity Code Authorisation determination:[25]

> The other aspect that must be developed in conjunction with action on structure is the need to develop demand side flexibility. The larger the demand uncertainty faced by generators relative to capacity, the more likely it is that all generators will have an incentive to bid aggressively because they face the prospect of being left out of the market during that trading period. However, the responsiveness of the demand side is likely to increase in the longer term.

3.4.2 Longer term pricing implications

The second way in which the features of the NEM have traditionally differentiated its pricing outcomes from other markets is that even under conditions of highly competitive bidding, periods of relatively elevated and depressed average wholesale prices can persist for extended periods – often, several years. This is due to the characteristics of electricity supply infrastructure and electricity demand discussed above:

- ***Low operating and high fixed and sunk costs*** – which contribute to barriers to entry and exit.
- ***Strong economies of scale*** – imply that in an environment in which demand is rising only gradually, it will often be efficient to wait longer to invest than in the absence of these economies.
- ***'Lumpiness'*** – means that the market may experience alternating periods of insufficient and excess supply, with the short run operating profits of plant oscillating from much higher-than-necessary to recover fixed costs to zero.[26]

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[24] For example, see AEMC, *Final Rule Determination, Potential Generator Market Power in the NEM*, 26 April 2013, available at: https://www.aemc.gov.au/rule-changes/potential-generator-market-power-in-the-nem.

[25] ACCC, *Applications for Authorisation, National Electricity Code*, 10 December 1997 (ACCC Code Authorisation), p.103, available at: https://www.accc.gov.au/public-registers/authorisations-and-notifications-registers/authorisations-register/national-electricity-code-mark-i.

[26] Electricity economist, Steve Stoft provides the following example: if baseload plant can only be built with a capacity of 1000 MW and peakers can only be built with a capacity of 100 MW, then if peak demand in the market is 7,750 MW, for an assumed set of costs and load profile, the optimal plant mix is six baseload plant and 19.75 peakers. In this context, he says, "Building 19 peakers would result in supply being short of demand for a duration 4 times greater than is optimal (2.5% instead of 0.62%), and this would cause peakers to over-recover fixed costs by a factor of four. These high profits would entice the entry of another peaker which would drop short-run profits to zero. This would stop entry as demand grew. With free entry and the uncertainties of a real market, short-run profits would average out to the level of fixed costs. But lumpiness would prevent the right

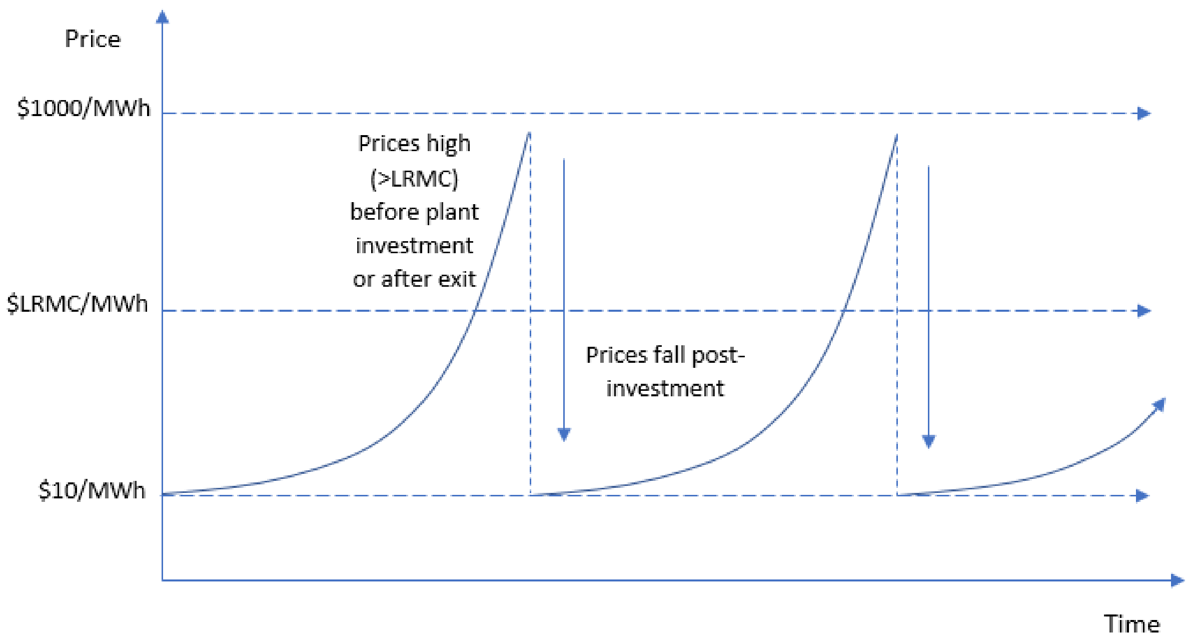
- ***Long lead times*** – the longer it takes to commission new plant, the longer that periods of insufficient supply may persist. Conversely, plant can be mothballed or retired relatively quickly, which can limit the duration of periods in which excess supply persists.
- ***Inelastic demand*** – while not almost completely inelastic as in the short run, electricity demand is still relatively inelastic in the longer term, contributing to sustained periods of high or low prices.

Taken together, these factors mean that prior to a generation investment being made (or after a major plant has been retired), average spot prices will tend to be higher than the long run equilibrium average price; and prices will be lower than the long run equilibrium in the period following an investment.

Figure 5 below shows how an energy-only market such as the NEM can exhibit a multi-year ‘cycling’ of average spot and contract prices under historically conventional conditions of rising demand and no major plant exits:

- In the period (which may be several months or years) prior to a new generation investment, average prices will be above the long run marginal cost (LRMC) of supplying market demand;
- Immediately after a large lumpy investment, average prices will be below LRMC; and
- If demand is rising over time, prices should gradually rise back towards and beyond LRMC.

Figure 5: Conventional price cycles in an energy-only market



Source: Frontier Economics

In the more recent scenario we have been observing in the NEM of RET-driven investment helping to trigger sporadic major plant exits, the dynamics of price-cycles are almost reversed, appearing more as they do in **Figure 6**.

(fractional) number for peakers from being built, and this would cause some inefficiency.” See Stoft, S., *Power System Economics, Designing Markets for Electricity*, IEEE Press 2002, p.131.

Figure 6: Recent RET-driven price-cycle dynamics

Source: Frontier Economics

It is important to note that given traditionally characteristic strong economies of scale, lumpiness and long lead times for generation development, such cycling of average prices is perfectly consistent with competitive and efficient participant behaviour and market outcomes.[27] However, the amplitude of such cycles can be exacerbated where existing participants are not pure price-takers and where barriers to entry to new generation investment are high, such as under the following circumstances:

- If incumbent generators have a high market share (as a result of benefitting from economies of scale), they may have a reduced incentive to invest because the subsequent 'collapse' in wholesale prices can substantially curtail their expected returns (although, in reality, incumbents in the NEM have invested with reasonable alacrity in the past and continue to do so).[28]
- Even new entrants might not find it worthwhile to invest given that entry requires high sunk costs to be incurred and can cause post-entry prices to fall significantly.
- The post-entry fall in prices also means that customers have a reduced incentive to invest in generation or demand-side response (DSR) themselves, because other customers who do not contribute to the new investment also benefit from lower prices (free-rider effects).

The recommendations in the ACCC's REPI and proposals in the Government's Consultation paper – and more generally, the sense that ordinary competition law is believed to be unsuitable and sector-specific rules for the NEM are necessary – seem to reflect a degree of frustration with the performance of the energy-only market, particularly over these longer time periods.

[27] For example, agricultural markets – in which producers (farmers) typically behave in a pure price-taking manner – can exhibit volatile 'cobweb' patterns of prices and volumes due to lags in the adjustment of supply (crops) to demand. See: https://en.wikipedia.org/wiki/Cobweb_model.

[28] See Part 2 of Appendix A on the drivers for the Somerton and Hallet OCGT plant.

3.4.3 Structural implications

The in-built short- and longer-term volatility of wholesale prices in an energy-only market such as the NEM has its own implications for the way market participants choose to structure their businesses.

Generators and retailers operating in the NEM are typically exposed to complementary risks:

- Generators are exposed to the risk that the (volatile) wholesale prices they are paid for their output may not be sufficient to finance their fixed and sunk costs and earn a reasonable profit; while
- Retailers and large customers are exposed to the risk that the price they pay for wholesale power will exceed the typically fixed[29] price they receive, respectively, from their customers or for their output.

The complementary nature of these risks mean that generators and retailers engage in either or both the following risk allocation activities:

- ***Purchase or sale of financial derivative contracts*** – that are settled against regional spot prices. NEM participants usually enter derivative contracts to hedge (rather than extend or speculate on) their natural spot price exposures. Accordingly:
  - Since generators have a natural long[30] exposure to the spot price, generators generally sell derivative contracts to hedge or offset their natural exposure.
  - Likewise, since retailers and large industrial customers have a natural short exposure to the spot price, these parties typically purchase derivative contracts to offset their natural exposure.
- ***Vertical integration*** – to provide an internal or 'physical' hedge against spot price risk. Vertical integration can consist of any of the following:
  - Acquisition of existing generation or retail assets
  - Establishment or development of new generation or retail assets or activities
  - Acquisition of rights to the outputs or cash flows of generation or retail activities, such as through Power Purchase Agreements (PPAs).

A key advantage of vertical integration over contracting is that vertical integration avoids or reduces the transaction costs associated with a generator or retailer/large customer needing to negotiate or trade derivative contracts on a regular basis to hedge its spot price exposures. Such costs can include:

- Operating and maintaining (as large) a trading team
- Meeting additional prudential requirements or providing additional credit support to counterparties
- Potentially paying higher prices for hedging due to significant counterparties or potential counterparties 'holding-up' contract (re)negotiations.

As noted in section 2.2.2 above, the ACCC in its REPI report acknowledged that vertical integration could offer efficiency benefits.

The remainder of this report considers the extent to which recent and forthcoming changes to technology, market architecture and the supporting infrastructure are likely, over time, to minimise the differences between the NEM and other more 'normal' markets that have given rise to the concerns recently expressed.

[29] 'Fixed' in this context refers to fixed with respect to the wholesale electricity price.

[30] 'Long' in this context refers to financially benefitting from a rise in the price of the underlying commodity (here, wholesale electricity). 'Short' has the opposite meaning.

4 TECHNOLOGY AND POLICY CHANGES

This chapter outlines the nature of changes to technology, market architecture and structural features of the NEM that are occurring or can be reasonably anticipated over the next decade.

4.1 Changes to generation & storage infrastructure

The previous chapter discussed the technical and economic characteristics of traditional electricity generation infrastructure that have contributed to short- and longer-term price volatility in the NEM. This section discusses how many of these characteristics have changed and are likely to continue changing and the likely implications for the future plant mix of the NEM.

More detail on existing generating plant types and sizes, likely future trends in plant technology and cost characteristics, and the potential future NEM plant mix is provided in Appendix B.

4.1.1 Historical trends in plant technologies, unit and station sizes

The S&P World Electric Power Plants Database (WEPP) database[31] is a worldwide inventory of generator technology investment decisions from 1960 to the present day. The WEPP provides interesting insights into historical trends in centralised generation investment around the world.

Focussing on 5 key countries (Australia, Canada, the United States, Germany and China), some of the most salient features are:

- Coal-fired and gas steam turbines, and to a lesser extent, hydro power stations are the largest generators built in each of countries examined, with unit sizes in Australia in the 250-750 MW range and station sizes of at least 500 MW.
- The number of coal-fired power stations built in developed countries has decreased in recent years.
- In Australia and the USA, coal-fired generator sizes have been falling, with the trend flat or mixed elsewhere.
- The trend in coal plant unit sizes appear to be falling in Australia and Canada, while rising in China and mixed elsewhere.

Appendix B provides more details.

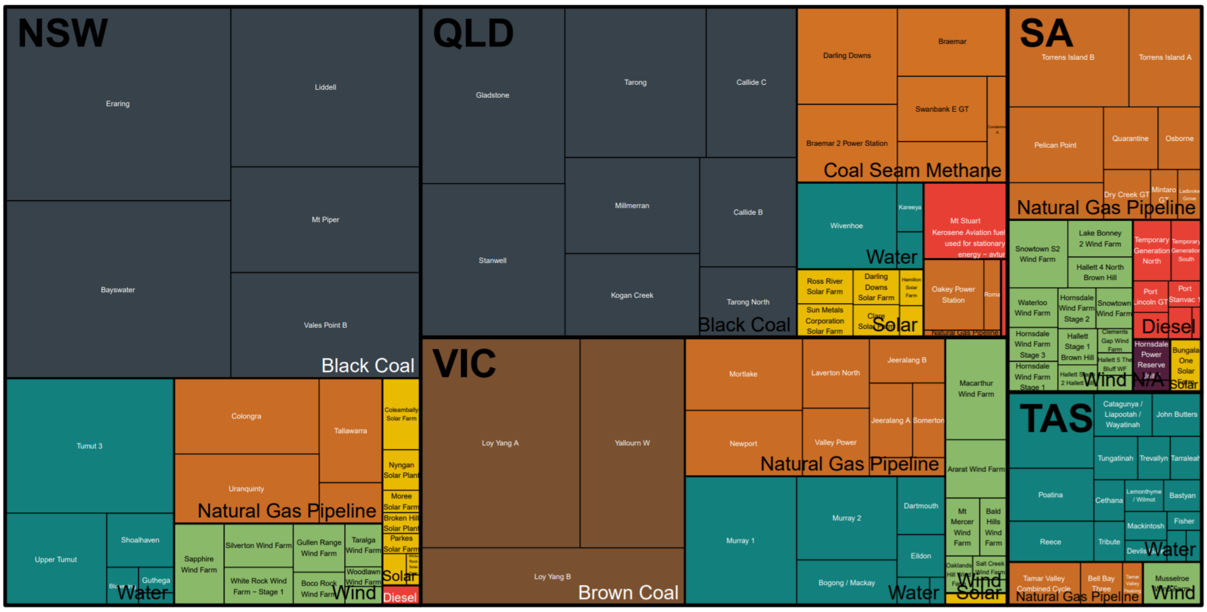
4.1.2 Current large-scale generation mix in the NEM

In spite of several recent coal-fired generator retirements, large coal-fired power stations in New South Wales, Queensland and (to a lesser extent, after the closure of Hazelwood) Victoria dominate the NEM energy mix, with the remaining generation stock consisting of smaller stations fuelled by gas, wind, solar and liquid fuels (**Figure 7**). The current dominance of coal plant is even more pronounced when considering relative output shares of different plant (**Figure 8**).[32]

[31] S&P Global Market Intelligence World Electric Power Plants Database – see: https://www.platts.com.es/products/world-electric-power-plants-database.

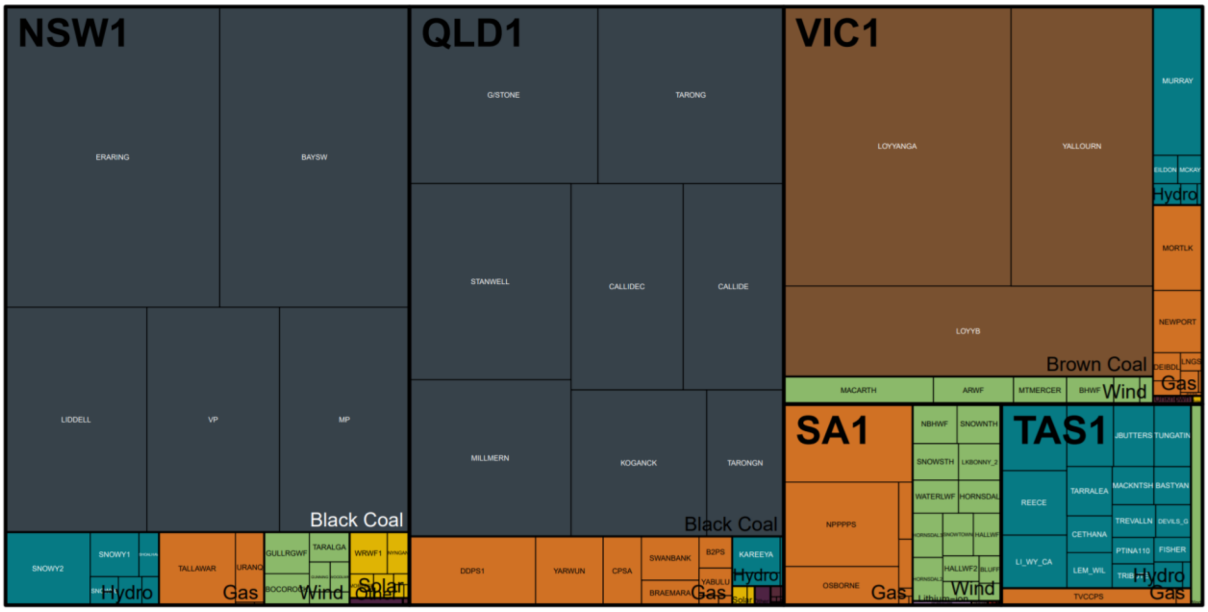
[32] Both Figures have been reproduced from Appendix B.

Figure 7: NEM station capacity by region and fuel type



Source: Frontier Economics analysis of AEMO data (generation information 2 November 2018)

Figure 8: NEM station output by region and fuel type

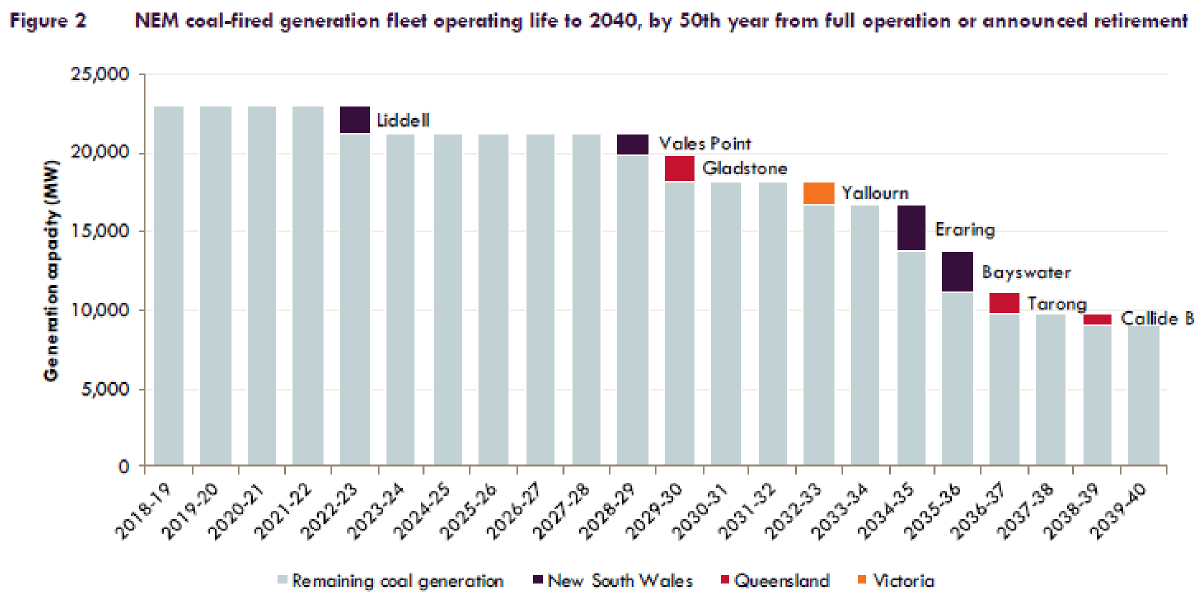


Source: Frontier Economics analysis of AEMO data (MMSDM)

Projected coal-fired plant retirements

Despite its present dominance of the NEM plant capacity and output mix, the overall level of coal-fired generation capacity has peaked and is likely to diminish in future decades due to ongoing plant retirements. **Figure 9** below shows the current stock of NEM coal-fired power stations and when they are due to be decommissioned according AEMO's Integrated System Plan (ISP).[33] Substantial retirements are due in the 2030s, and are unlikely to be replaced with new coal. In our view, it is possible that some of these retirements (e.g. Yallourn) may be brought forward into the 2020s.

Figure 9: AEMO ISP projections of coal-fired power station retirements



Source: AEMO ISP, p.22.

4.1.3 New energy technologies and costs

New energy technologies include all of the following types of infrastructure:

- Large-scale wind plant
- Rooftop solar PV units
- Solar thermal plant
- Small-scale ('behind the meter') and large-scale (grid-connected) storage, including batteries and pump storage
- Energy management systems.

As discussed in the ACCC REPI report, virtually all additions to the NEM's stock of generation in recent years have involved renewable plant. The REPI notes that:[34]

> Of around 2500 MW of new generation investment over the past six years, well over 90 per cent has been in renewables. Since 2013, no material thermal generation has been added to the market.

The pace of investment in renewable generation has increased since the resolution of the Commonwealth RET in mid-2015:[35]

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33 AEMO, *Integrated System Plan for the National Electricity Market*, July 2018 (ISP), Figure 2, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

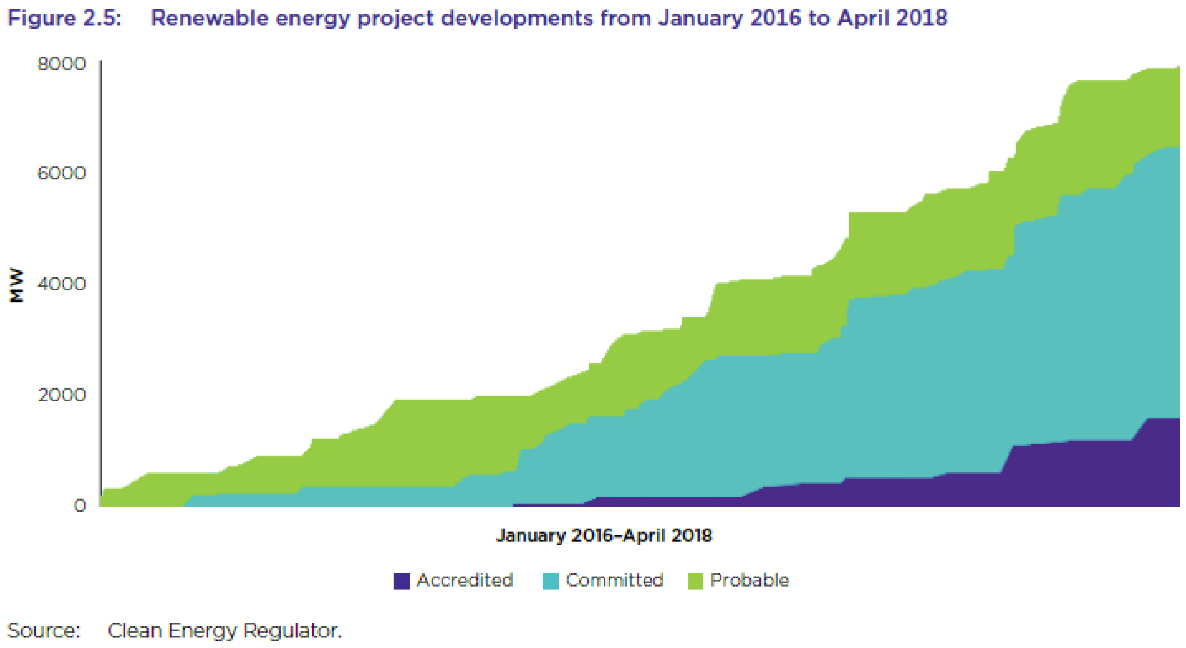
34 ACCC REPI, p.46.

35 ACCC REPI, p.46.

> As at March 2018, nearly 90 per cent of the 4400 MW of committed generation investment coming into the NEM is either wind (2032 MW) or solar PV (1877 MW).30 A similar percentage of the 45000 MW of proposed projects in the NEM are also renewables (39 per cent wind, 38 per cent solar and 11 per cent hydro), with the remainder mostly gas plant.

See also **Figure 10** below.

Figure 10: Recent trend in renewable energy project developments



Source: ACCC REPI, p.46.

Evidence on lumpiness and scale economies for new technologies

A 2015 study by CO2CRC[36] found that lumpiness and economies of scale for renewable technologies are far less significant than for large fossil-fuelled power stations. This lack of both features applies at both the unit level and the overall plant or station level.

For example, wind turbines investigated in the study consist of 3 MW turbines, with farm sizes of 50 MW and 200 MW, reflecting the availability of much smaller capacity increments than traditional technology types. Further, wind exhibited fairly modest economies of scale by the standards of traditional fossil-fuelled plant, as demonstrated by the following plant costs:

- Capital cost (sent-out):
  - 50 MW: $2,550 / kW
  - 200 MW: $2,450 / kW
- Operating and maintenance (O&M) cost (per annum):
  - 50 MW: $60 / kW
  - 200 MW: $55 / kW

[36] Wiley, D., Neal, P., Ho, M. 2015, Fimbres Weihs, G., Australian Power Generation Technology Report, CO2CRC, CSIRO, ARENA, Office of the Chief Economist (Federal Department of Industry and Science) and anlecr&d (CO2CRC et al (2015)). See Appendix B.

These figures indicate that potential investors in wind generation face relatively weak incentives to invest in large and expensive projects, and hence are likely to face fewer financing and other barriers to investing.

CO2CRC also evaluated solar PV at residential (5 kW), commercial (100 kW) and utility-scale (10 MW and 50 MW) sizes, with utility-scale plant assessed with fixed, single-axis and dual-axis mounts. In all cases, economies of scale were again fairly limited:

For fixed module mounting:

- Capital cost (sent-out):
  - 5 kW: $2,100 / kW
  - 100 kW: $1,950/ kW
  - 10 MW: $2,400 / kW
  - 50 MW: $2,300 / kW
- O&M cost (per annum):
  - 5 kW: $30 / kW
  - 100 kW: $30 / kW
  - 10 MW: $30 / kW
  - 50 MW: $25 / kW

For utility-scale dual-axis module mounting (which offers the highest capacity factors):

- Capital cost (sent-out):
  - 10 MW: $3,600 / kW
  - 50 MW: $3,400 / kW
- O&M cost (per annum):
  - 10 MW: $45 / kW
  - 50 MW: $40 / kW

This relatively wide spread of available capacity increments combined with gently-declining slopes of renewable energy average cost curves is likely to promote the recent trend of smaller, geographically diverse and independently-owned renewable power stations (see below). This, in turn, will help reduce the importance of existing retail market positions in helping to support or underwrite new capacity additions, thus lowering barriers to entry and expansion.

Projected changes in new technology costs

Generation

Recent research produced by the CSIRO highlights the falling costs of new generation technologies.[37] Hayward & Graham (2017) developed cost projections for a range of both conventional and new technologies out to 2050 taking into account 'learning effects' – which reduce deployment costs – and modelled costs under two scenarios: 2 degrees (formerly 450 ppm) and 4 degrees (550 ppm) warming. Selected projections for the latter scenario are provided below (see also Appendix B). As the figures show, less developed renewable technologies (solar PV and solar thermal) are still expected to benefit

[37] Hayward, J.A. and Graham, P.W. 2017, *Electricity generation technology cost projections: 2017-2050*, CSIRO, Australia (Hayward & Graham (2017)), available at: https://publications.csiro.au/rpr/download?pid=csiro:EP178771&dsid=DS2.

from substantial learning effects and cost reductions over time. However, given the relative maturity of wind technology, the unit costs of wind are not expected to fall significantly.

Figure 11: Solar thermal, wind and solar PV cost projections

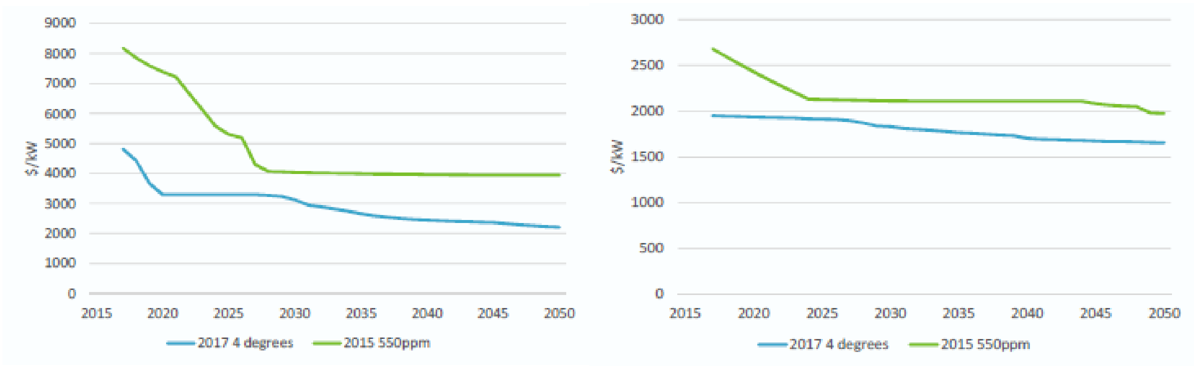


Figure 3-3: Solar thermal with 6 hours storage (left) and wind (right)

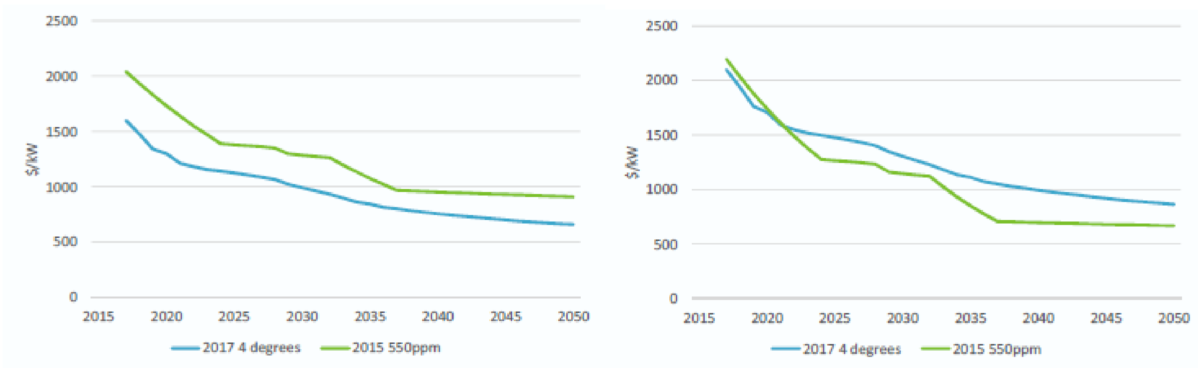


Figure 3-4: Rooftop solar photovoltaics (left) and large scale solar photovoltaics (right)

Source: Hayward & Graham (2017), p.9.

The cost projections for rooftop solar PV and batteries (see below) were updated in 2018 in Graham et al (2018).[38] See also Appendix B.

Traditional generation technologies were not expected to not exhibit anything like the same cost reductions.

[38] Graham P.W., Wang D., Braslavsky, J., and Reedman L.J. 2018. *Projections for small-scale embedded technologies, Report for AEMO*, CSIRO, Australia (Graham et al (2018)), available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/Projections-for-Small-Scale-Embedded-Technologies-Report-by-CSIRO.pdf.

Batteries

Battery storage is projected to benefit from continued learning-based cost reductions in the near term. Of all the technologies discussed, storage is the most modular, has very short lead times and economic lifespan, which reduces long term investment risk and lowers barriers to investment.

Hayward & Graham (2017) also projected future costs of batteries, finding even more rapid reductions were likely than previous bullish forecasts (see **Figure 12**). While battery costs are projected to fall rapidly and substantially, balance of plant costs (referring to the required parts of the station excluding the battery itself) are significant and benefit less from learning. This will slow overall cost reductions of the technology.

Figure 12: Battery-only cost projections: 2017 update and previous projections, 2017 $A

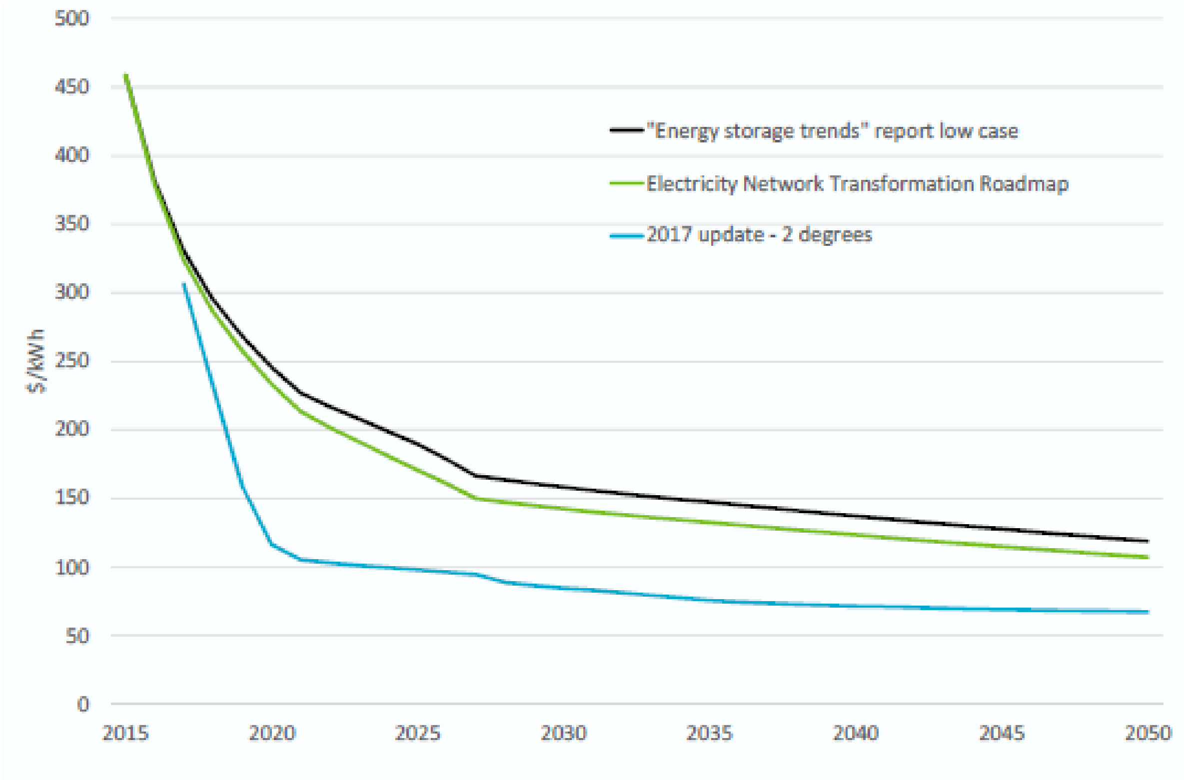


Figure 3-12: Comparison of battery only cost projections: 2017 update and previous projections, 2017 AUS dollars

Source: Hayward & Graham (2017), p.14.

CSIRO published updated cost projections for batteries – including balance of plant costs – in 2018.[39] See also Appendix B.

4.1.4 Projected changes in generation plant mix

The trends discussed above suggest that reductions in costs, economies of scale and lumpiness of generating plant will continue to occur over the next decade. However, these reductions will largely be driven by an ongoing shift in the *types* of technology investors favour, rather than taking place within

[39] Graham et al (2018).

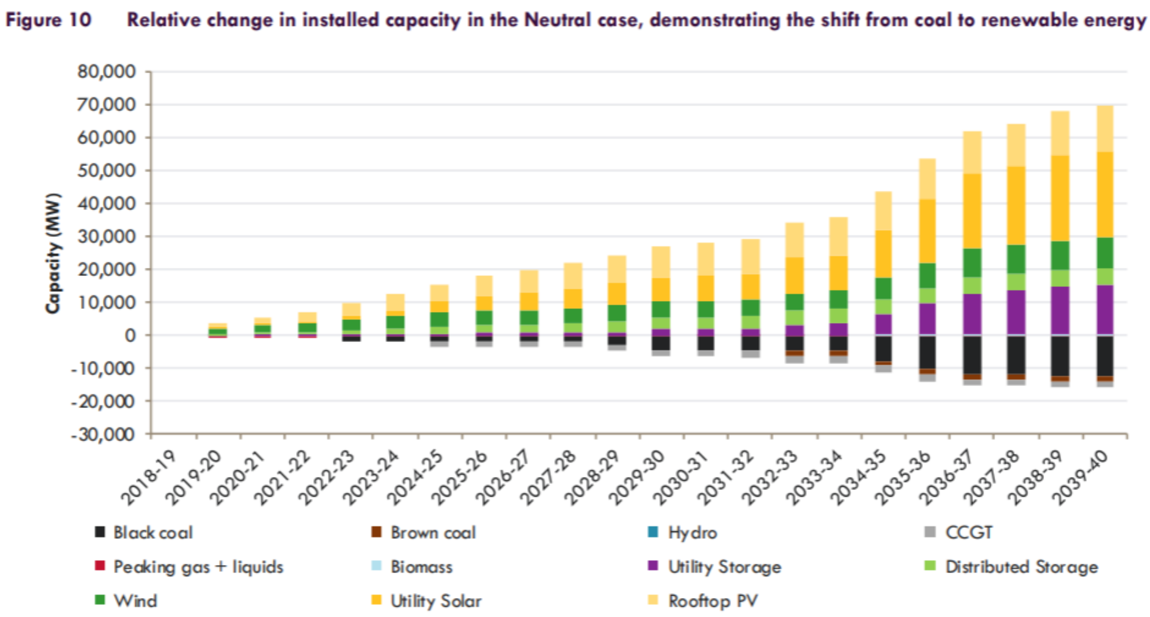
traditional types of generation. In short, new plant investment is likely to exhibit the following changes in characteristics relative to historical patterns of plant development – new plant will tend to reflect:

- Renewable and storage technologies rather than fossil-fuelled technologies; and
- Smaller economies of scale and smaller capacity increments, which combined with shorter development lead-times should result in more 'right-sized' and timely additions to the stock of plant than previously.

Having regard to changing generation cost structures and trajectories of demand growth, federal and state environmental policies and their financing implications, and planned transmission expansions (see below), generation investment in the NEM and the overall NEM plant mix is likely to be substantially different in a decade's time than it is now. Investment in new coal-fired power stations and more generally steam turbines is unlikely to be substantial. As in recent years, generation investment is likely to be dominated by many relatively small utility-scale wind and solar projects, with a continuing steady uptake of residential solar PV. In addition, it is likely that a substantial quantity of battery storage will be required, even if Snowy 2.0 proceeds.

Figure 13 reproduces Figure 10 from AEMO's ISP, which shows the relative changes in installed capacity in the 'Neutral' planning scenario relative to the present generation mix over the next 20 years. It highlights the growth in both rooftop PV and utility solar (solar thermal), as well as the ongoing growth of wind, and the beginnings of significant investment in distributed and utility-level storage.

Figure 13: AEMO ISP projections of changes in plant mix



Source: AEMI ISP, p.38.

4.2 Transmission expansion

As noted in Box 1: transmission expansion in the NEM has traditionally been undertaken according to an overall system cost minimisation criterion. This criterion has been applied by jurisdictional transmission businesses on a project-by-project basis. However, following from the recommendations of the 2017 Finkel Review,[40] AEMO published its initial ISP in July 2018.

The ISP recommends a large number of transmission investments in three tranches, depending on how urgent AEMO considers them to be. The first tranche (Group 1) comes at a cost of $450-650 million and includes:

- Increase transfer capacity between New South Wales, Queensland, and Victoria by 170-460 MW.
- Reduce congestion for existing and committed renewable energy developments in western and north-western Victoria.
- Remedy system strength in South Australia.

The second tranche (Group 2) is designed to be completed by the mid-2020s to support new 'renewable energy zones' or 'REZs' and consists of:

- New transfer capacity between New South Wales and South Australia of 750 MW (RiverLink).
- Increased transfer capacity between Victoria and South Australia by 100 MW.
- Increased transfer capacity between Queensland and New South Wales by a further 378 MW (QNI).
- Connecting renewable energy through the above developments.
- Coordinating distributed energy resources (DER, primarily solar PV and batteries) in South Australia.

The third tranche (Group 3) is designed to support REZs and system reliability and security and is to be undertaken by the mid-2030s and beyond.

4.3 Better access to wholesale prices via the internet, 'smart' software and DER optimisation

Developments in communications technology have enabled tariffs and services previously restricted to large energy consumers to be offered to the mass market. Type 4 ('smart') meters measure electricity consumption at periodic intervals (typically 30 minutes) and remotely report readings, removing the need for manual meter reads. Smart meters were rolled out in Victoria between 2009 and 2015 under state regulations[41] and are gradually being installed in other NEM regions principally via opt-in and new-and-replacement meter policies. Smart meters enable network businesses and retailers to set tariffs with more sophisticated and cost-reflective charging bases than anytime consumption.

The AEMC made a rule change in late 2014 that imposed more prescriptive obligations on distribution networks to set cost-reflective network tariffs.[42] As a result, most distribution networks now offer optional time-of-use and maximum demand tariffs to residential and small business customers, and many businesses are moving to mandatory or opt-out assignment of cost-reflective tariffs to new customers, as well as existing customers installing or changing solar PV or battery units.[43]

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[40] *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, Commonwealth of Australia 2017 (Finkel Review), Recommendation 5.1, p.124.

[41] See: http://www.smartmeters.vic.gov.au/about-smart-meters/reports-and-consultations/advanced-metering-infrastructure-cost-benefit-analysis/2.-background#.

[42] AEMC, *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule* 2014, 27 November 2014, available at: https://www.aemc.gov.au/rule-changes/distribution-network-pricing-arrangements.

[43] AEMC, *Economic Regulatory Framework Review, Promoting Efficient Investment in the Grid of the Future*, 26 July 2018, section 7.3.2 and Table 7.2, pp.110-112, available at: https://www.aemc.gov.au/markets-reviews-advice/electricity-network-economic-regulatory-framew-1.

Importantly, for the purposes of this report, traditional time-of-use (ToU) and demand (and even critical peak pricing or CPP) tariffs do not necessarily imply a greater elasticity of real-time wholesale electricity demand. Rather, tariffs aimed at signalling times of peak demand in advance will tend to *reduce* actual electricity demand at the relevant times, rather than increase the *sensitivity* of demand to real-time wholesale prices.

That said, communications technology has increased economic opportunities for customers to provide real-time demand-side responses via alerts or autonomous controls or systems. On a residential level, several networks are offering incentives to install devices that enable them to control customer air-conditioner thermostats remotely[44] during peak events. To date, the emphasis on residential product offerings has focussed on times of network peak events rather than wholesale market peak events, but this has started changing following recent rule changes to promote competition in metering[45] and the contestability of distributed energy services.[46] On a commercial level, offerings of demand-side management hardware and software services attempt to minimise businesses' costs by optimising the timing of flexible loads, predicting wholesale price spikes, and initiating demand-side responses during peak periods. An example of these offerings is GreenSync's PeakResponse product.[47] In addition:

- ERM offers a pool price pass-through contract for consumers with an electricity bill spend of over $30,000 per annum;[48] and
- Amber offers a pool price pass-through contract for residential consumers, presently only in New South Wales.[49]

Falls in the price and increases in the energy density of chemical battery storage have made electricity storage products financially and/or practically feasible for some customers to install in their homes or businesses. Industry reports suggest that residential battery storage install rates almost quadrupled from about 6,000 systems in 2016 to around 23,000 systems in 2017.[50] Further, all the mainland NEM states have now announced battery subsidy schemes offering several thousand dollars of benefit per unit and with an overall target of nearly 100,000 installations. On the other hand, AEMO has recently revised down its battery forecasts in its 2018 Electricity Statement of Opportunities (2018 ESOO)[51] in light of recent reductions in wholesale electricity prices – see **Figure 14**.

[44] See: https://www.geelongadvertiser.com.au/news/geelong/powercor-energy-partner-program-offers-financial-incentive-for-airconditioning-control/news-story/2aaf7d403b9d4779de3ad7bd01912191 and https://www.ergon.com.au/network/manage-your-energy/incentives/peaksmart-air-conditioning.

[45] See: https://www.aemc.gov.au/rule-changes/expanding-competition-in-metering-and-related-serv.

[46] See: https://www.aemc.gov.au/rule-changes/contestability-of-energy-services.

[47] See: https://greensync.com/solutions/greensync-pr/.

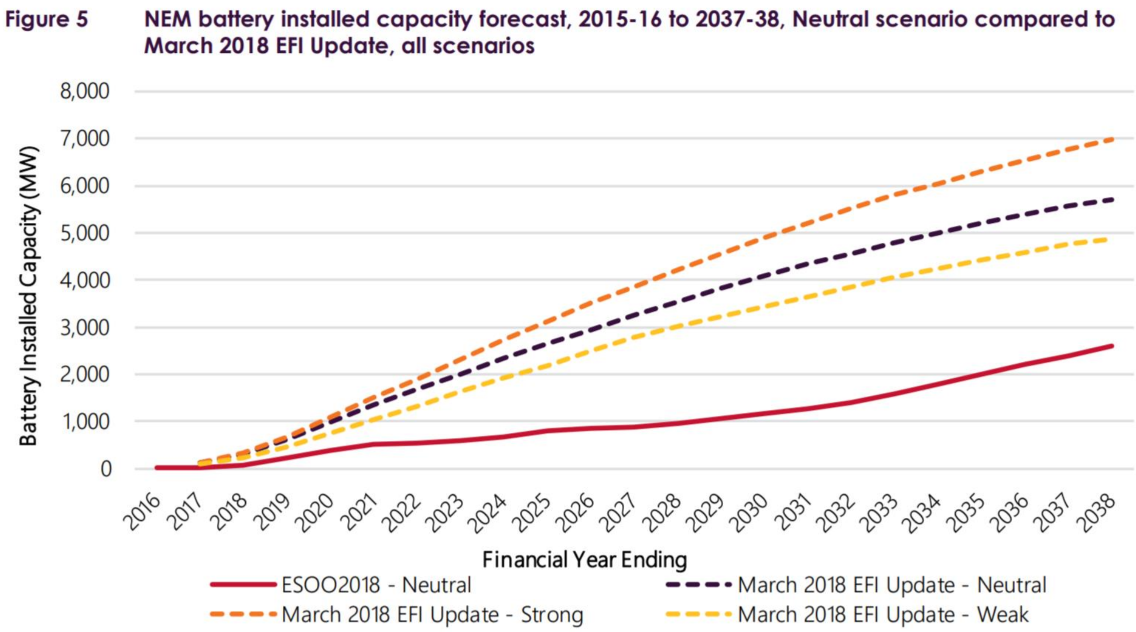
[48] See: https://ermpower.com.au/business-energy/energy-products/.

[49] See: https://www.amberelectric.com.au/.

[50] See: http://www.sunwiz.com.au/index.php/2012-06-26-00-47-40/73-newsletter/434-australian-battery-markettrebles-in-2018.html

[51] AEMO, *2018 Electricity Statement of Opportunities, A report for the National Electricity Market*, August 2018 (AEMO 2018 ESOO), available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

Figure 14: AEMO 2018 ESOO forecast of NEM battery installations



Source: AEMO 2018 ESOO, p.28.

Several businesses and governments have trialled Virtual Power Plant (VPP) programs, which enable registered wholesale market participants with control over a number of distributed generation and/or storage products to optimise operation of the systems in response to wholesale and or network price incentives. Notable examples of VPP schemes include the South Australian Government/Tesla VPP[52] and various retailer/independent offerings of AGL, Simply Energy and Reposit Power.

At a regulatory and market design level, work is progressing between Energy Networks Australia (ENA), AEMO and distribution networks on arrangements for the future improved optimisation of distributed energy resources (DER), such as small-scale solar PV, battery storage and ‘behind-the-meter’ energy management systems. The AEMO and ENA’s recent Open Energy Networks consultation paper[53] describes three broad long term options for enabling the dynamic coordination of DER in the power system. These options involve real-time dispatching of ‘active’ (controllable) DER in such a way as to maximise the value of the energy and ancillary services DER can provide without violating network security constraints, as well as better utilising DER as an alternative to network capex. While both the preferable model and the specific actions necessary to implement it are as yet uncertain, it is likely that regulatory changes will be required at some stage to enable the full value of falling DER costs and rising DER capability and penetration to be harnessed.

52 See https://virtualpowerplant.sa.gov.au/virtual-power-plant.

53 AEMO and ENA, *Open Energy Networks, Consultation Paper*, 15 June 2018, available at: https://www.energynetworks.com.au/open-energy-networks-consultation-paper.

4.4 Three-year notice of generator closure

On 8 November 2018, the AEMC made a final rule that requires large electricity generators to provide at least three years' notice to the market before closing.[54] The rule change was based on one of the recommendations in the Finkel Review.[55]

The AEMC considered that the provision of this advanced information will help market participants respond to possible future shortfalls in electricity generation, such as by building replacement capacity in a more timely manner. In so doing, it will eliminate incumbents' informational advantage over other parties as to when new generation investment may be viable. This should reduce the risks of entry and promote wholesale competition.

4.5 5-minute settlement

In November 2017, the AEMC made a final rule to change the settlement period for the electricity spot price from 30 minutes to five minutes, starting on 1 July 2021.[56] The delay of over three and a half years was provided to mitigate the costs and risks associated with implementation.[57]

The implications of moving to 5-minute settlement for policy-makers' concerns are discussed in the following chapter.

4.6 Demand response mechanism

The Finkel Review found that demand response plays a relatively small role in the NEM and recommended that the COAG Energy Council should direct the AEMC to undertake a review to recommend a mechanism that facilitates demand response in the wholesale energy market.[58]

In the REPI, the ACCC recommended the development of a demand response mechanism for the NEM to enable third parties who are not retailers to offer demand response directly into the wholesale market, "given its potential to constrain the pricing of generation businesses, limit the need for additional generation and lead to lower prices."[59]

In its final report for the Reliability Frameworks Review, the AEMC supported the development of a rule change to implement a mechanism that would enable demand response aggregators to be treated on an equal footing with generation.[60] On 31 August 2018, the Public Interest Advocacy Centre (PIAC), Total Environment Centre and the Australia Institute submitted a rule change request to implement a wholesale demand response mechanism.[61] Subsequently, the AEC submitted its own proposed rule

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[54] AEMC, *National Electricity Amendment (Generator three year notice of closure) Rule 2018*, 8 November 2018, available at: https://www.aemc.gov.au/rule-changes/generator-three-year-notice-closure.

[55] *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, Commonwealth of Australia 2017 (Finkel Review), Recommendation 3.2, pp.87-97.

[56] AEMC, *Rule Determination, National Electricity Amendment (Five Minute Settlement) Rule 2017*, 28 November 2017 (AEMC 5-minute settlement determination), available at: https://www.aemc.gov.au/rule-changes/five-minute-settlement.

[57] AEMC 5-minute settlement determination, p.vi, 17 and chapter 7.

[58] Finkel Review, Recommendation 6.7, p.148.

[59] ACCC REPI, p.204.

[60] AEMC, *Final Report, Reliability Frameworks Review*, 26 July 2018 (AEMC Reliability Frameworks Review), available at: https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review

[61] Public Interest Advocacy Centre, Total Environment Centre and the Australia Institute, *Wholesale Demand Response Energy Market Mechanism: Rule Change Request*, 31 August 2018, available at: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

change supporting the development of demand response, which the AEC says could provide many of the benefits of the PIAC et al rule change, but at significantly lower costs.[62] Then on 30 October 2018, the South Australian Government submitted a third, related rule change request that would allow third parties to offer wholesale demand response into the wholesale market as well as set up a separate wholesale demand response market.[63]

The AEMC has published a consultation paper on all three rule change proposals.[64] Given the support a demand response mechanism has received from the ACCC, AEMC and the COAG Energy Council, it is likely that something of this nature will be implemented in the next two to three years.

4.7 LNG import terminals

AGL is one of several parties considering building a LNG import facility on the east coast of Australia. AGL's proposed facility is at Crib Point on Western Port Bay in Victoria.[65] The Crib Point terminal would utilise a floating storage and regassification unit (FSRU) which stores the liquid gas and could allow between 12 to 40 LNG ships per year to resupply the FSRU with LNG. AGL anticipated that the first deliveries of LNG could occur in early 2020. However, the Victorian government recently decided to conduct a full environmental assessment for the project, which at the least would likely delay commissioning beyond this date.[66]

If the Crib Point project or one like it were to proceed, it would enable LNG to be supplied from overseas or elsewhere in Australia, providing more certain supply and greater price competition for east coast gas supplies.

62 Letter from Sarah McNamara, Chief Executive Officer, Australian Energy Council, to John Pierce, Chair, Australian Energy Market Commission, "Demand Response Mechanisms", 18 October 2018, available at: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-register-mechanism.

63 Letter from The Hon Dan van Holst Pellekaan MP, Minister for Energy and Mining to John Pierce, Chair, Australian Energy Market Commission, "Proposed Rule change – Demand Response Mechanisms", 30 October 2018, available at: https://www.aemc.gov.au/rule-changes/mechanisms-wholesale-demand-response.

64 AEMC, Consultation Paper, Wholesale Demand Response Mechanisms, 15 November 2018, available at: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

65 See: https://www.agl.com.au/about-agl/how-we-source-energy/crib-point-project.

66 See: https://www.theaustralian.com.au/business/mining-energy/agl-energys-plan-to-import-gas-at-crib-point-faces-delay/news-story/110f34f2e3d69d539f43bd42aec359e9.

5 IMPLICATIONS OF TECHNOLOGY AND OTHER CHANGES

Chapter 3 explained how certain key features of the NEM likely contributed to short and longer term price outcomes that have attracted the attention of policy-makers and regulators. Chapter 4 outlined a range of technology and market design changes affecting the NEM that can be reasonably anticipated over the next decade. This chapter brings together the themes explored in the previous two chapters by examining the implications of the expected technology and other changes for future market conduct and outcomes in coming to a view on whether the factors underlying policy-makers' historical and recent concerns are likely to persist over the next decade and beyond.

This chapter proceeds by examining the potential influence of the technology and other changes discussed in chapter 4 on the features of the NEM that I believe have driven policy-makers' concerns laid out in chapter 3. Specifically, this chapter considers how various forms of technology and other policy and market changes will likely affect those features of the NEM that together have led to high and prolonged sensitivity of wholesale prices to demand and supply conditions (and thereby the benefits of vertical integration) – these features being:

- The nature of generation technology – as exhibiting high fixed and sunk costs, large economies of scale, 'lumpiness' and long lead-times
- The energy-only design of the NEM, combined with
- Highly inelastic nature of real-time wholesale electricity demand.

5.1 Expected changes in generation technology and costs

As discussed in Appendix B and summarised in chapter 4, it is likely that over the next decade, generation technology will move more rapidly in the direction it has been moving over the decade – towards more renewable generation capacity and storage and away from conventional fossil-fuelled generation. As a consequence, new electricity generation in particular is likely to exhibit:

- ***Less irreversibility (or 'sunkness')*** – some plant types (such as batteries and micro-generators) will be smaller and more portable than traditional fossil-fuelled turbines, and many new technology plant have shorter asset lives. Both of these factors will tend to reduce barriers to entry and exit.
- ***Weaker economies of scale*** – renewable generation and battery storage technologies exhibit much smaller average unit cost declines with larger unit and plant sizes than traditional technologies, making it efficient to invest at a smaller scale – and sooner – than previously would have been optimal.
- ***Reduced lumpiness*** – renewable generation and battery storage technologies are available in much smaller increments than fossil-fuelled units, making it possible to take advantage of smaller economies of scale to invest sooner than otherwise and without creating the same capacity overhang and 'price collapse' effects as the commissioning of new generators created in the past.
- ***Shorter lead times*** – enabling quicker market reactions to high demand conditions.

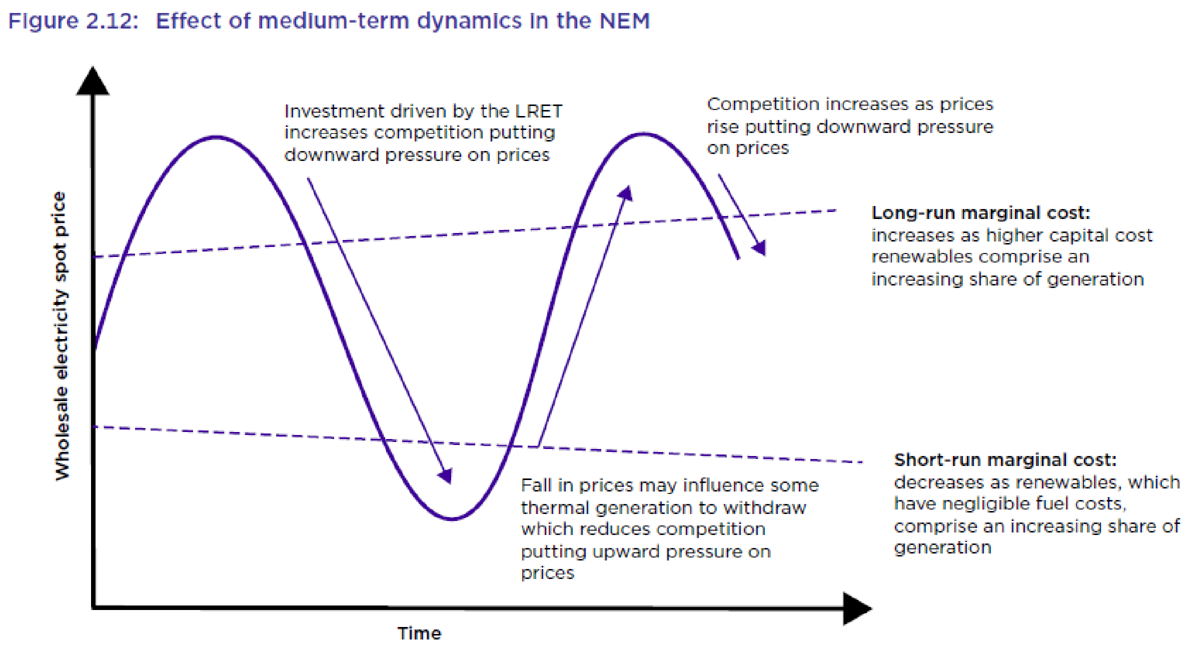
All of these factors are likely to encourage faster and smaller-sized market responses to periods of relative undersupply than has previously been the case. They should also help reduce the importance of (i) existing retail market positions and (ii) fear of price collapse effects in developing new capacity additions, thus lowering barriers (such as they are) to entry and expansion.

The impact of such changes has already been evident following the closure of the Northern and Hazelwood power stations in South Australia and Victoria, respectively. While the South Australian Government has instigated a number of supply-side investments itself, elsewhere, the investment response to date has been largely driven by market responses to high wholesale prices and the existing Commonwealth RET.[67]

Further, less irreversible or shorter-lived generation and storage that can be commissioned without long lead times could encourage faster market responses to high prices.

The likely future effect of these changes can be shown using a similar stylised approach to the price-cycling phenomenon shown in **Figure 5**. In this context, I note the following figure from the AEMC's 2017 Residential Price Trends report[68] (as adapted from the Grattan Institute's Next Generation report[69]) and reproduced by the ACCC in the REPI (**Figure 15**). This figure purports to show contemporary NEM price-cycle dynamics.

Figure 15: Cycle of wholesale prices in the energy-only NEM with the RET



Source: AEMC 2017 Residential Price Trends report, Figures 1 and 3.3, pp.v and 23; ACCC REPI, Figure 2.12, p.53.

The Grattan / AEMC figure appears to be based on an expectation of minimal future changes to generation technology and costs across the dimensions highlighted above – investment cost reversibility, economies of scale, lumpiness and development lead times. If these aspects of generation technologies and costs change over the next decade in ways that appear likely, NEM price-cycle dynamics in both the short term and the medium to longer term could change considerably.

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[67] See: https://www.energycouncil.com.au/analysis/tracking-ret/.

[68] AEMC, *Final Report, 2017 Residential Electricity Price Trends*, 18 December 2017, available at: https://www.aemc.gov.au/markets-reviews-advice/2017-residential-electricity-price-trends.

[69] Grattan Institute Next Generation report, Figure 3.1, p.17.

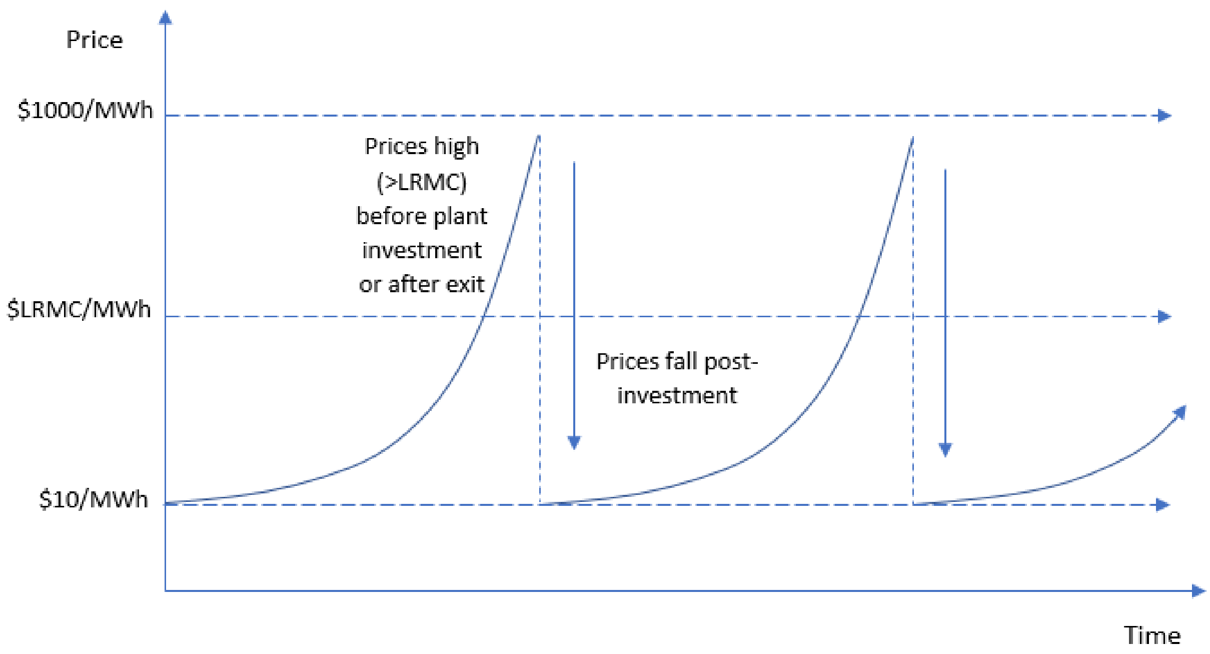
5.1.1 Implications for short term price dynamics

Wholesale prices *may* become more volatile in future (as suggested by the Grattan / AEMC figure) over short time horizons to the extent that the proportion of intermittent generation capacity increases and is not complemented by storage and/or more real-time demand response. If very little demand response emerges, then short term prices could become more volatile than they are now. However, given the market design (section 5.2) and technological moves (section 5.3) supporting greater real-time demand response and less strategic generator bidding behaviour, it is quite likely that short term prices could eventually become *less volatile* than they are presently.

5.1.2 Implications for medium to longer term price dynamics

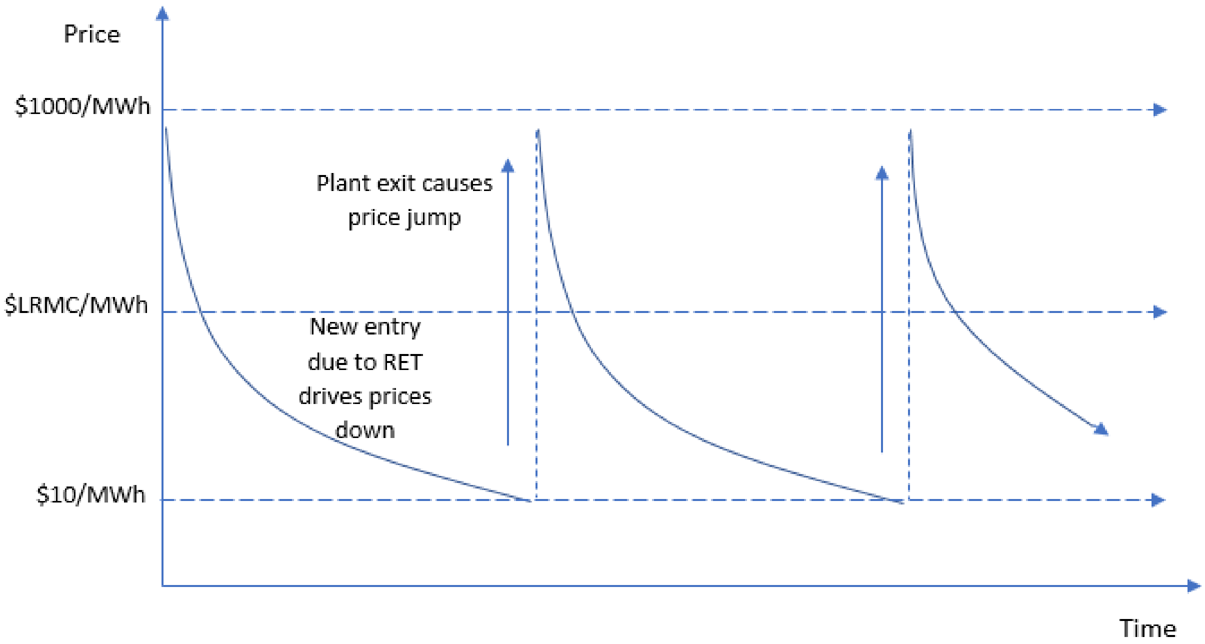
The expected changes to generation technology discussed in chapter 4 could reduce the amplitude of medium to longer-term price cycles. Recall the historical NEM price-cycles presented in **Figure 5** and **Figure 6**, reproduced below in **Figure 16** and **Figure 17**, respectively.

Figure 16: Conventional price cycles in an energy-only market



Source: Frontier Economics

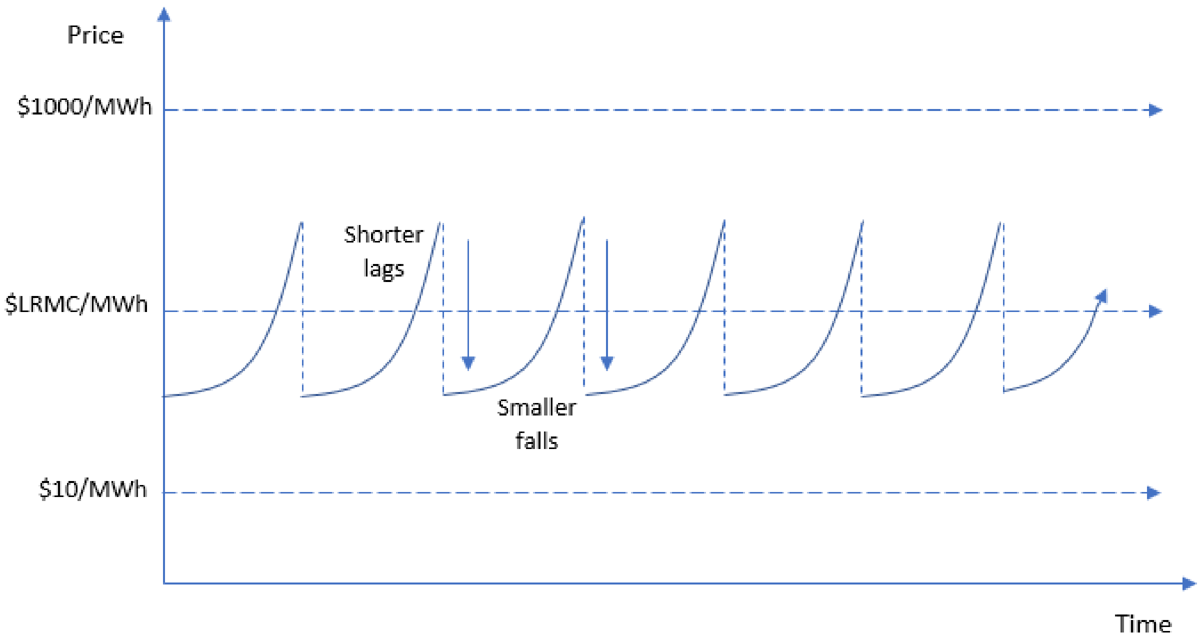
Figure 17: Recent RET-driven price-cycle dynamics



Source: Frontier Economics

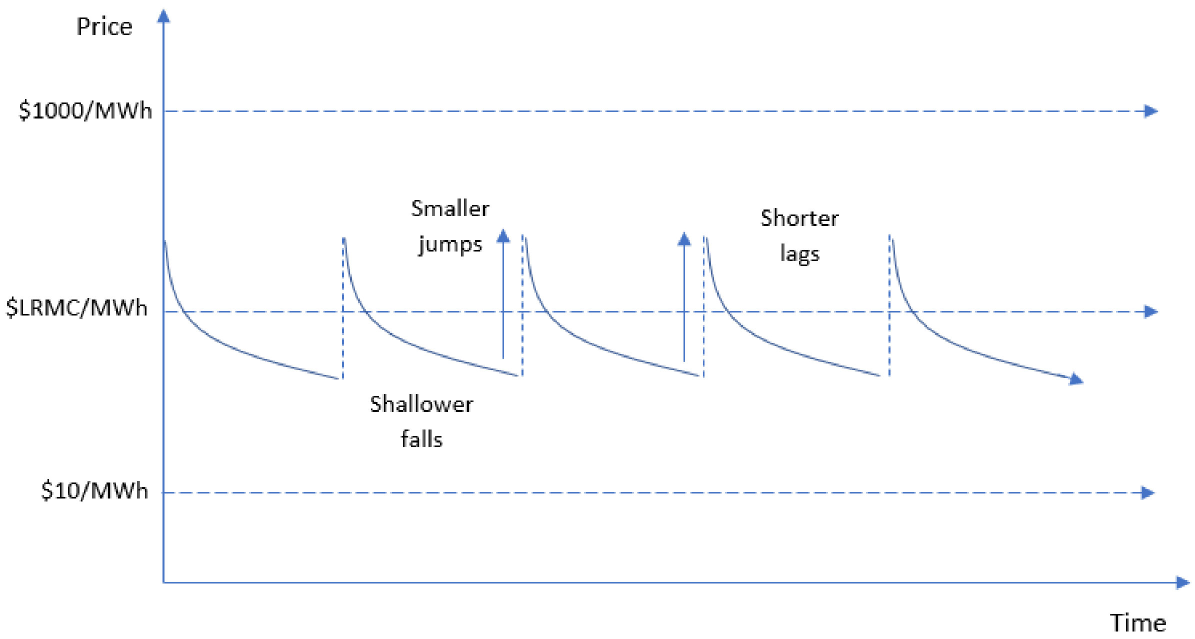
In my view, medium to longer-term price cycles are likely to shift over the next decade towards cycles that appear more like those in **Figure 18** and/or **Figure 19** below.

Figure 18: Future conventional price cycles in the NEM



Source: Frontier Economics

Figure 19: Future RET-driven price cycles in the NEM



Source: Frontier Economics

To the extent that electricity demand grows and plant exits are limited or delayed, price cycles should resemble those in **Figure 18**. The smaller scale of potential generation investment means both that:

- Incumbents face less of a 'price collapse' deterrent to investing in a timely manner; and
- New entrants face reduced financing and other barriers to generation investment.

Both of these factors should mean that investment happens more promptly and in smaller increments than has historically been the case. The result is a flatter price cycle over the medium to longer term.

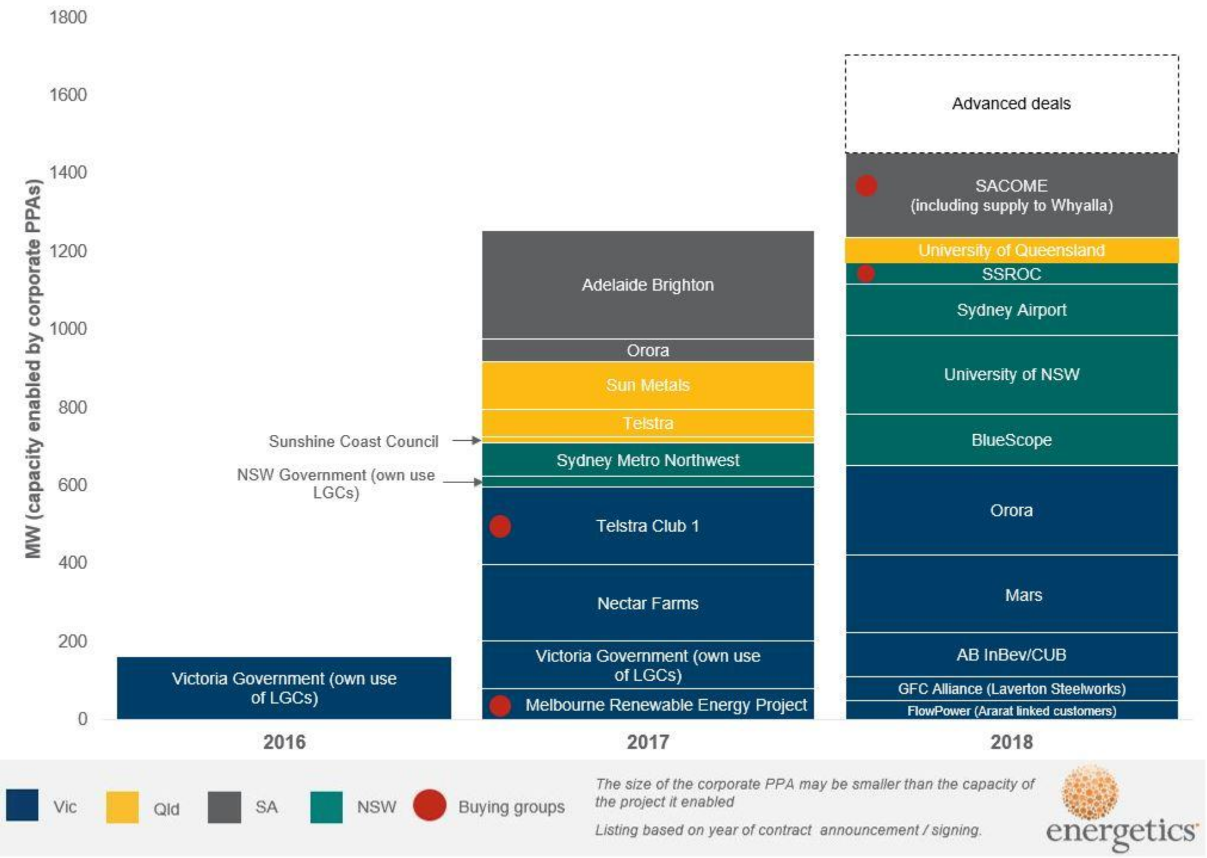
In the perhaps more likely scenario that coal-fired generators gradually continue to exit the market and renewable energy targets drive a sizeable proportion of all new generation investment, future price cycle dynamics could more resemble those in **Figure 19**. The recently-imposed requirement for a three-year notice of closure combined with the shorter lead times for new generation technology investments should mean that wholesale prices do not rise as much following a plant exit as they did following the departure of Hazelwood because investors will have time to anticipate and invest in advance the closure. Further, the three-year notice requirement may encourage plant owners to err on the side of bringing forward closures to avoid the risk of being obliged to run their plant when wholesale prices drop to very low (circa 2015) levels. This should mean that other things being equal, wholesale prices do not fall to as low levels prior to a plant exit as they did prior to the closure of Northern and Hazelwood.

5.1.3 Implications for the benefits of vertical integration

Changes in generation technology and costs should also limit the benefits of vertical integration, particularly the importance of large retail positions in sponsoring or underwriting new generation investment.

Strong evidence for the proposition that economies of scale and lumpiness are not presenting barriers to end-customer investment in renewable technologies is provided by data on recent power purchase agreements (PPAs). There is an emerging trend of corporate energy consumers signing PPAs directly with generators on much smaller scales than has historically been typical in the NEM. **Figure 20** illustrates recent public corporate PPA deals in the NEM from 2016 to 2018. These PPAs enable prospective wholesale market entrants with projects in the hundreds or even tens of MW to contract their output to one or several customers, rather than selling to an existing retailer or building a retail portfolio. In signing long term PPAs, financers are willing to accept high debt-to-equity ratios, lowering the weighted average cost of capital (WACC) for the prospective entrant and increasing the economic viability of the project. Direct contracting in this manner reduces barriers to entry for prospective market participants and diminishes the benefits of vertical integration – see also section 5.1.3.

Figure 20: Corporate renewable energy PPA deals



Source: Energetics corporate renewable energy PPA deal tracker https://www.energetics.com.au/insights/knowledge-centres/corporate-renewable-ppa-deal-tracker/

It is clear that many such investments are being made in reliance on some form of renewable subsidy program – whether the Commonwealth RET, or the Victorian or Queensland RETs (VRET and QRET, respectively) – rather than price signals from the energy-only market alone. However, a substantial amount of investment in addition to that motivated by RETs will be required by 2030 to meet the NEM reliability standard, and such investments will need to be driven by wholesale market signals.

One interpretation of the PPA evidence is that heralds the beginning of the end for the advantages of the gentailer business model. While it is unlikely that business consumers sponsoring new small-scale renewable plant via PPAs are presently bypassing the need to contract with a retailer for hedging services (who in turn would need to own or contract with flexible suppliers), this may become more realistic in the future.

Over the next decade, for the reasons discussed in sections 5.2 and 5.3, smaller consumers are likely to have much greater access to the following:

- Battery storage to help manage troughs in energy supply from remote or local intermittent renewable generation
- Energy management technology and service providers to facilitate more flexible demand response to both weather conditions and owned or contracted intermittent renewable plant output and
- Wholesale market rewards for scheduled demand response.

This does not mean that consumers will bypass retailers entirely, but that retailing could become a narrower function focussed on providing settlement and billing services. That is, the need for retailers to offer wholesale price hedging to consumers could lessen and the benefits of vertical integration could decline as a consequence. To the extent this occurs – and the extent remains uncertain at this stage – this could mitigate competition concerns about vertical integration.

5.2 Expected changes in market design and structure

Chapter 4 discussed two key changes to market design that are expected over the next few years or have been foreshadowed by the AEMC. The first is the planned move to 5-minute settlement in July 2020 and the second is the AEMC's intention (following the Finkel Review recommendation) to introduce a demand response mechanism. Both of these changes could reduce short term volatility in wholesale prices. Chapter 4 also discussed the prospect of a major push for investment in transmission expansions across the NEM, driven by the ISP, and also the prospect of a new LNG import terminal. These developments are also discussed below.

5.2.1 ISP transmission expansions

If Group 1 and 2 projects proceed over the next few years as the ISP recommends, then assuming modest demand growth, the NEM is likely to experience fewer inter-regional constraints than it does at present. Fewer constraints mean that generators, demand-side response and storage in different locations will be able to compete more effectively to discipline prices in a given region. Given that the ACCC has consistently adopted state-based market definitions in its competition analysis, a reduced incidence of inter-regional constraints should help alleviate regulator and policy-maker concerns over regional wholesale concentration and contract liquidity levels.

5.2.2 Effect of 5-minute settlement

The move to 5-minute settlement will likely change the nature of bidding incentives. With no assurance that they will remain dispatched beyond a 5-minute period, generators responding to a spike in spot prices will have stronger incentives to incorporate any start-up costs in their offer prices. On its own, this could raise the volatility of spot prices. To the extent that generators become less willing to offer cap contracts, retailers will need to raise retail tariffs to help compensate for the higher hedging costs and risks they will be forced to manage.

On the other hand, larger and relatively slower-to-respond coal- or even most gas-fired generators could face weaker incentives to engage in strategic behaviour to raise prices – to the extent this incentive remains following the AEMC's late rebidding rule change[70] – because any resulting increase in prices may not persist for long enough to make such conduct worthwhile.

70 See https://www.aemc.gov.au/news-centre/media-releases/new-rules-for-last-minute-electricity-market-rebid.

5.2.3 Effect of demand response mechanism

Assuming the adoption of changes to the market arrangements to promote greater demand response (particularly, scheduled demand response), along the lines of either of the proposals discussed in section 4.6, the extent of real-time demand response is likely to increase in the future. This should increase the real-time responsiveness or elasticity of electricity demand with respect to the wholesale price – see also section 5.3 below.

5.2.4 Access to alternative fuel sources

As discussed in section 4.7, AGL is one of several parties considering building a LNG import facility on the east coast of Australia. If the Crib Point project or one like were to proceed, it would enable LNG to be supplied from overseas or elsewhere in Australia, providing more certain supply and greater price competition for east coast gas supplies.

Access to an alternative source of gas at internationally-traded prices should, other things being equal, lead to less medium-term volatility in gas prices and hence less medium-term volatility in wholesale electricity prices to the extent that gas generation remains marginal at peak demand times. This is likely to be the case over the next decade.

5.3 Expected changes to demand elasticity

Leaving aside changes to the market design or rules, section 4.3 explained how improvements in communications technology and metering have increased economic opportunities for customers to provide real-time demand-side responses via alerts or autonomous controls or systems. Further, the scope for much improved DER optimisation could help ensure that DER is applied to whatever purpose – wholesale or network demand response – offers the greatest benefits. At times of peak system demand (and given the likely infrequency of constraints on distribution networks), this is likely to be electricity demand that is more responsive to wholesale prices. Over time, these developments should result in a more elastic wholesale demand for electricity.

A more elastic real-time demand for electricity will help reduce price volatility in the short term in two key ways:

- First, real-time demand that is more responsive to wholesale prices will reduce the price impact and hence ‘payoff’ to generators of a given size from withdrawing or pricing-up their capacity to spike prices, relative to the incentives for such behaviour that might otherwise prevail. Further, new entrant retailers will have access to similar physical hedging options as large gentailers do now (i.e. new entrants can pick and choose a ‘right-sized’ physical generation hedge to match their small loads), with the result that financial hedge premiums should reflect efficient risk allocation rather than any market power.
- Second, even where generators largely behave as price-takers, more elastic real-time wholesale demand should reduce the extent to which wholesale prices spike in the event of events such as unexpectedly high system peak demand and/or sudden major plant outages.

Even with a relatively modest degree of real-time demand responsiveness, both the incentives on generators to engage in strategic bidding and even the need for a MPC to enable the spot market to clear can diminish. These developments would help bring the NEM more into line with other markets in the economy and potentially reduce policy-makers’ and regulators’ concerns about the efficient and competitive functioning of the electricity sector.

5.4 Implications for the achievement of the NEO

The developments discussed in this chapter are likely to offer three major benefits from the perspective of policy-makers and regulators:

- The first is that they should help smooth wholesale price volatility in both the short term and in the medium to longer term;
- The second is they should reduce the advantages of the vertically-integrated ‘gentailer’ business model; and
- The third is that they should encourage more competitive behaviour in the NEM wholesale market and thereby lead to more efficient and cost-reflective dispatch and pricing outcomes.

These developments are also broadly consistent with the satisfaction of the NEO, although only the third is directly relevant. Reduced price volatility may or may not promote the NEO in itself, but is expected to be a consequence of behaviours that would promote the NEO – namely, more efficient participant decisions about energy usage and investment, and more cost-reflective bidding. Similarly, reduced advantages for the gentailer business model may not promote the NEO directly, but could increase competition by lowering entry barriers.

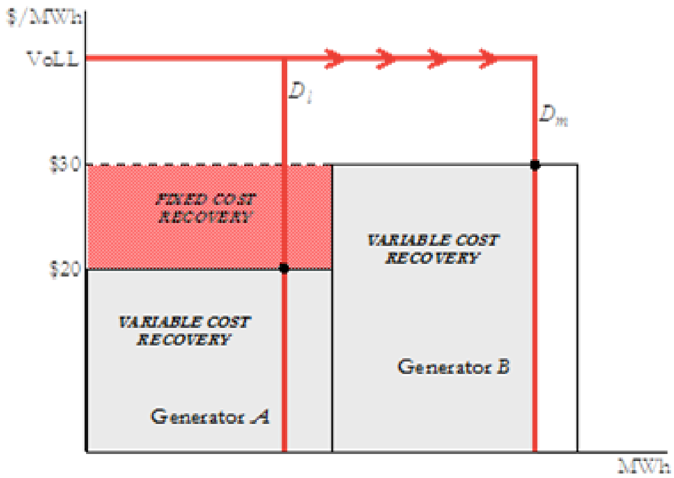
A ENERGY-ONLY WHOLESALE MARKET OPERATION

Part 1 – Fixed cost recovery

Figure 21 and **Figure 22** below illustrate the concept of fixed cost recovery in an energy-only wholesale electricity market graphically. Assume two generators (A and B) utilise different technologies. Generator A is a coal-fired plant used for baseload supply and has a relatively low variable cost of supply. Generator B is a gas-fired plant used for peaking supply and has a relatively high variable cost of supply. Demand is a sideways "L-shape" since demand is perfectly inelastic for prices below the MPC.

At times of low demand (Dl) only Generator A is selected to run (in line with least-cost dispatch) and hence the spot price is set at $20/MWh. Since this is equal to Generator A's variable costs, this generator is recovering only its variable costs of supply.

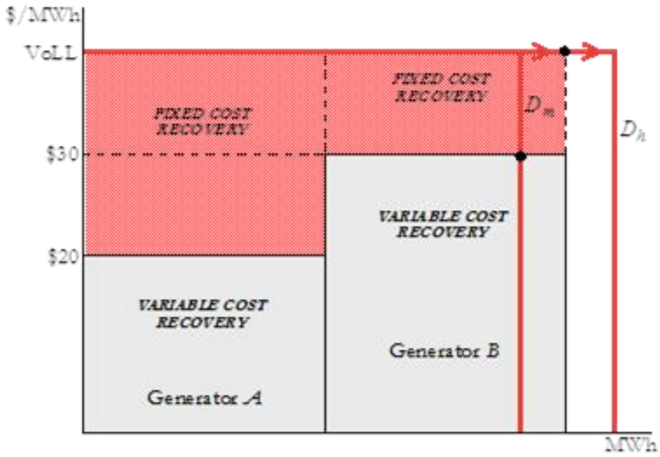
Figure 21: Recovery of fixed costs during times of medium demand



Source: Frontier Economics

At times of medium demand (Dm) both Generator A and B are selected to run and hence price is set at $30/MWh. Since $30/MWh is greater than Generator A's variable cost of $20/MWh, during times of medium demand Generator A recovers both its variable costs and some contribution towards its fixed costs. Since $30/MWh is equal to Generator B's SRMC, this generator is recovering only its variable costs of supply.

Figure 22: Recovery of fixed costs during times of high demand



Source: Frontier Economics

At times of high demand (Dh), where demand outstrips supply, price will approach the MPC and thus both generators will recover their variable costs of supply and some contribution towards their fixed costs.

Part 2 – Optimal plant mix

The energy-only market design is not only intended to yield consistent levels of unserved energy and installed generation capacity, it can also produce an efficient technology mix of plant. In a theoretically ideal (fully-competitive) energy-only market in which all generators bid at their avoidable operating costs, for a given:

- MPC
- mix of available generation technologies (with differing cost and operating characteristics) and
- shape or 'profile' of load,

the market should produce:

- the optimal technology mix and timing of generation investment as well as the optimal operation of these generators, together ensuring that long-run total costs of meeting load are minimised and
- a path of market prices that results in this optimal mix of plant – based on optimal dispatch – perfectly recovering all generators' total costs (fixed and variable) over time.

The precise conditions necessary for this outcome are not borne out in practice due to a range of real-world market imperfections and failures. For example, it ignores generator start-up costs, which are typically material for conventional thermal generators (such as coal and gas-fired plant) but are not typically factored into estimates of operating cost.

Nevertheless, it is illustrative to describe how in theory an energy-only market seeks to ensure the efficient mix and operation of generation plant, as well as cost recovery for that efficient mix of plant.

Different types and technologies of generating plant have different fixed and variable costs. 'Baseload' plant, such as coal-fired generators, tend to have relatively high fixed costs and relatively low variable costs. This structure of costs means that it is efficient for them to operate at high capacity for a large proportion of the time. ‘Mid-merit’ plant such as combined cycle gas turbines (CCGTs) tend to have moderate fixed and variable costs, making it efficient for them to operate for a moderate proportion of the time. ‘Peaking’ plant, such as open-cycle gas turbines (OCGT), tend to have relatively low fixed costs and relatively high variable costs. This structure of costs means that it is efficient for them to operate for a small proportion of the time, such as during hot or cold weather when electricity demand is high.

As noted above, for efficient plant to recover their full costs in an energy-only market, the wholesale spot price must be able – and expected – to rise above the operating cost of all technologies of plant from time to time, to enable each plant type to recover its fixed (as well as variable) costs:

- When the spot price rises above the operating cost of baseload plant, baseload plant earn ‘infra-marginal’ rents that contribute towards the recovery of their fixed costs.
- When the spot price rises above the operating cost of mid-merit plant, both peaking and mid-merit plant earn infra-marginal rents that contribute to the recovery of their fixed costs.
- When the spot price rises above the operating cost of peaking plant, all plant (baseload, mid-merit and peaking) earn infra-marginal rents that contribute to the recovery of their fixed costs.

The level and shape or ‘profile’ of demand over time will – in combination with generator and demand-side bids – influence how often and for what duration the spot price lies above or below the operating costs of various plant. The expected level and profile of the spot price will over time influence which plant are likely to be profitable and enter or exit the market.

Figure 23 below provides a stylised illustration of how energy-only markets signal an efficient plant mix. The top panel shows the total cost, per MWh, of three generation technologies at different operating capacity factors. The y-intercept denotes fixed cost and the slope of the line denotes variable cost. Depending on the duration of operation, each technology is at some point least-cost in $/MWh terms (ie it lies on the dotted red line). These ‘screening curves’ can be used to determine the optimum plant mix for a given shape of load.

Taking as given the target maximum annual magnitude of unserved energy, it is possible to derive the optimal proportion of time that each plant should run and the resultant optimal level of installed capacity of each plant from the middle panel.

Under the assumptions of a fully-competitive market, the:

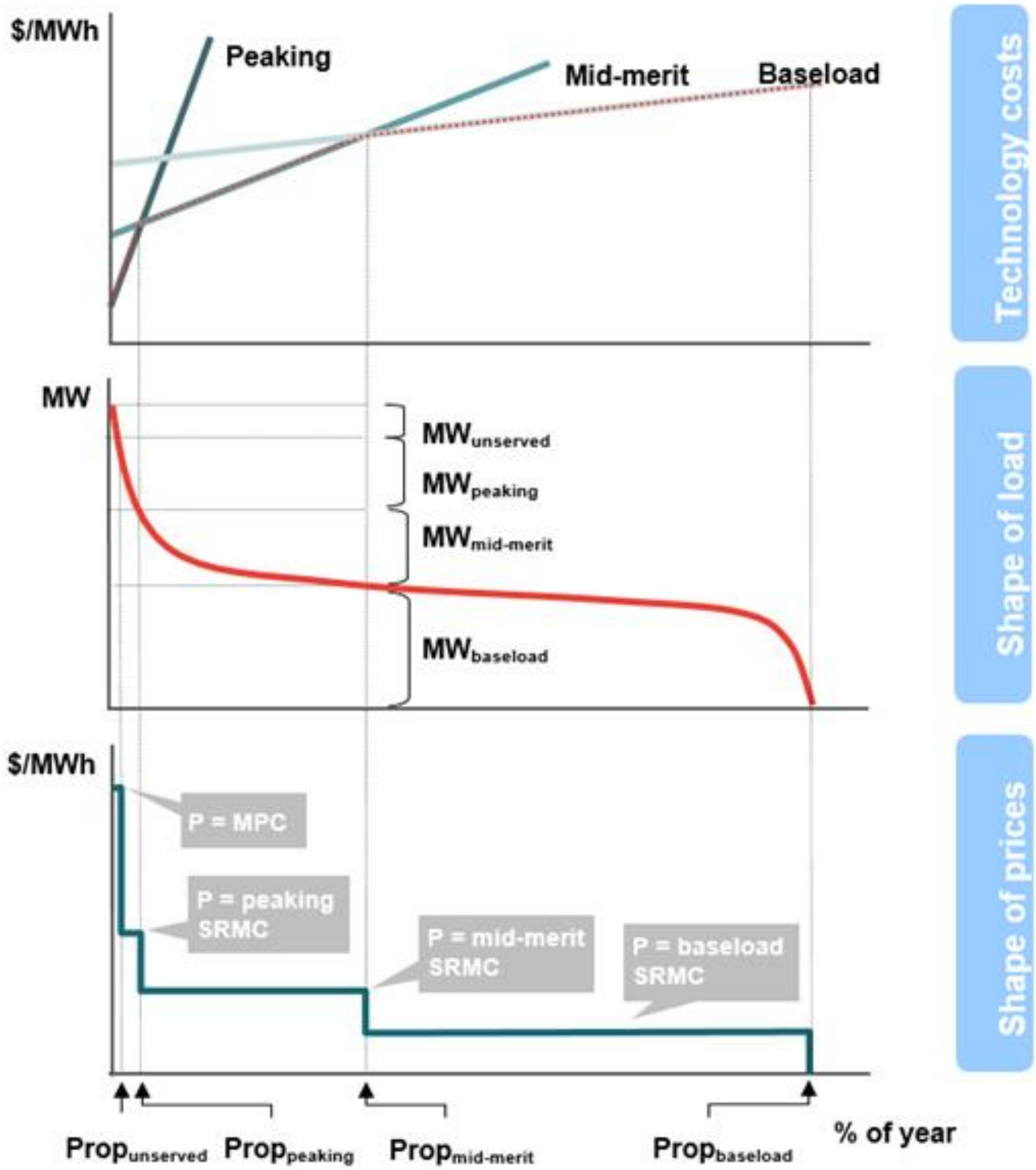
- optimal duration of unserved energy, combined with the
- optimal plant mix and operation given technology costs and the shape of load,

can be used to derive an optimal price-duration curve as per the bottom panel.

This resultant price-duration curve is sufficient to ensure that all technologies in the optimal mix can recover their total costs (variable and fixed) over time. Each technology recovers only its variable costs when it is setting the price (i.e. it is the marginal generator). Each technology recovers both its variable and a portion of its fixed costs when the market price rises above its variable cost. This means that:

- The most expensive generation technology recovers its fixed costs only when it is required to be dispatched meet demand, or during periods of unserved energy when the market price is equal to the MPC.
- All other generation technologies in the optimal mix also rely on MPC prices at these times to ensure they fully recover their fixed costs. For example, a baseload unit will recover some of its fixed costs when a mid-merit plant is marginal and setting the price, but will not recover all its fixed costs unless the optimal duration of MPC prices occurs.

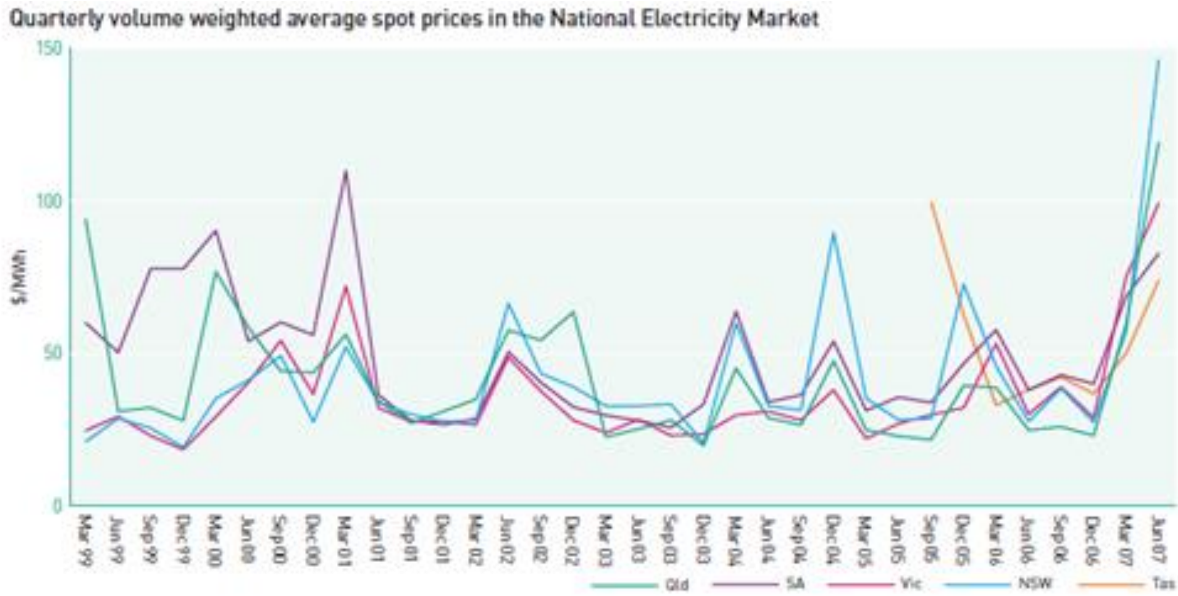
Figure 23: Technology costs, optimal plant mix and price-duration curve



Source: Frontier Economics

Investment in unsubsidised (non-renewable) generation have generally reflected the predictions of energy-only market theory. When the NEM commenced, there was considerable coal baseload capacity in Victoria but limited gas peaking capacity (although Snowy Hydro's plant played this role to some extent). Through the course of several hot summers, when demand and spot prices in Victoria and South Australia rose sharply for short periods of time (see **Figure 24**), investors realised that while additional baseload plant would not be viable, lower fixed cost peaking plant that would only operate for a few days or weeks a year could be profitable. The result was the development of the gas-fired Somerton OCGT in Victoria and the gas/diesel Hallett OCGT in South Australia.

Figure 24: NEM spot prices 1999-2007



Source: AER, State of the Energy Market 2007*, Figure 2.9, p.90.*

B LITERATURE REVIEW

Part 1 – Historical trends in generation technology in the NEM

World Electric Power Plants Database

The S&P Global Market Intelligence World Electric Power Plants Database[71] (WEPP) is a worldwide inventory of electric power generating units. This database can be used to examine historical trends in centralised generation investment around the world. Entries in this database include information about unit sizes, station sizes, construction year, operating status, technology, fuel type and location.

This report uses the WEPP data to investigate trends in generator technology investment decisions from 1960 to the present day. To obtain a subset of projects of interests, we perform some basic filtering prior to presenting the following results. Our filtering methodology is as follows:

- We select five significant countries of interest, including Australia.
- We consider the most common fuels utilised in Australia, including coal, gas, water (hydro), solar and wind.
- We only consider power stations greater than or equal to 30MW in size. Many projects in the database are embedded (decentralised), which we consider separately in the following section. We use a 30MW minimum station capacity as a heuristic to filter out decentralised projects which would otherwise skew results.

The following figures show distributions via box-and-whisker plots[72] of station size by technology and country (**Figure 25**) and unit size by technology and country (**Figure 26**) in five year periods. We aggregate projects by fuel type, but split gas into technology categories of steam turbine and 'other', as there is a distinct step change in the size of steam turbine gas generators compared to other gas generator technology types[73]. For stations with units built in different years, we attribute the modal (most frequent) year of unit construction to the station[74].

From **Figure 25**, it is clear that coal-fired and gas steam turbines, and to a lesser extent, hydro power stations are the largest generators built in each of countries examined. Most remarkably in Australia, coal-fired power stations have consistently dominated other fuel groups – small coal-fired power stations in Australia are comparable in size to large power stations of other fuel types.

The number of coal-fired power stations built in developed countries has decreased in recent years, likely due to a combination of the following reasons:

- Flattening or falling demand in the selected countries other than China
- Carbon pricing or abatement risk, leading to investment in low-carbon emitting substitutes

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[71] See: https://www.platts.com.es/products/world-electric-power-plants-database

[72] The methodology for calculating elements of the box and whiskers is known as Tukey's methodology. The elements of the box include 25th, 50th and 75th percentiles. The whiskers represent the most extreme values falling within the 25th/75th percentiles plus/minus the interquartile range (IQR), which is the difference between the 75th and 25th percentile. Outliers include any values more extreme than the 25th/75th percentiles plus/minus the IQR.

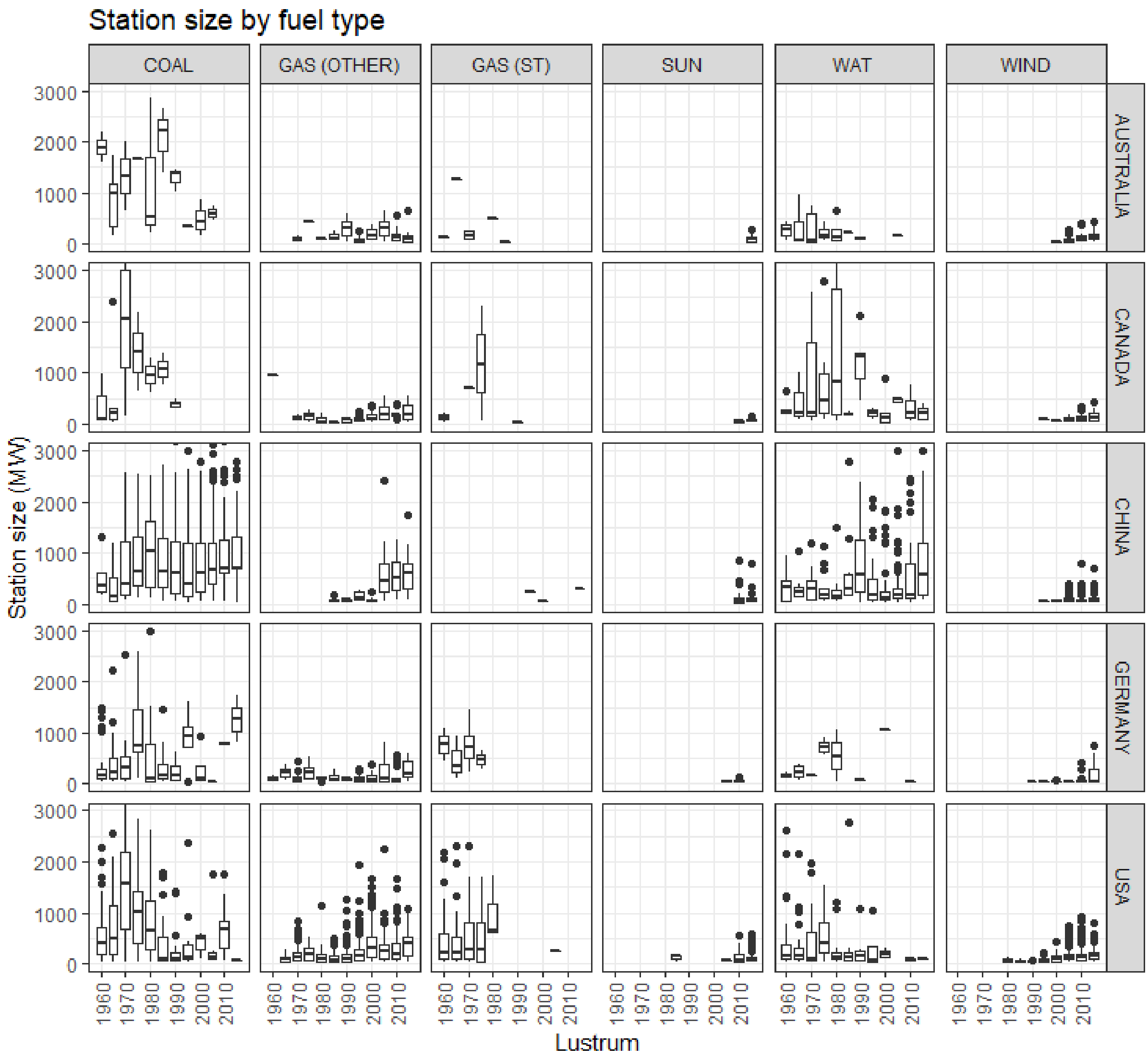
[73] There are a large number of possible configurations for gas-fired power stations with similar unit/station size characteristics. (footnote)The relatively new single shaft combined cycle configuration (both prime-movers attached to a single shaft) has favoured larger units, explaining recent increases in size in the US and China

[74] This explains several data points seemingly missing from **Figure 25** from data in **Figure 26**.

- Requirements for flexibility in systems with increasing variable renewable energy (VRE) – coal-fired power stations (large steam turbines) are generally slow to respond to rapid changes in demand and supply conditions.

In Australia and the USA, coal-fired generator sizes have been falling. The size trend for coal stations is flat in China and mixed in Germany.

Figure 25: Station size by fuel type



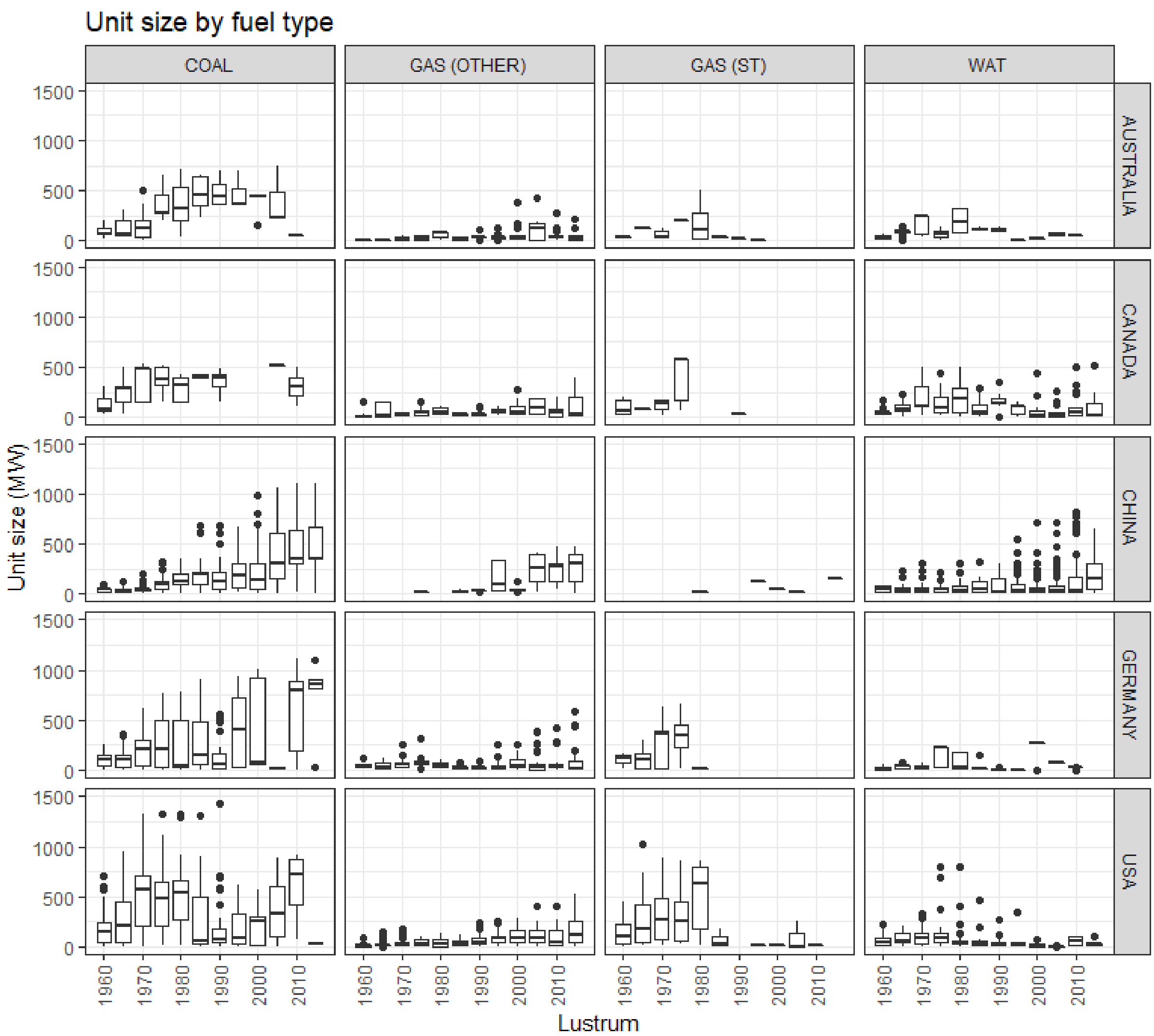
Source: Frontier Economics analysis of WEPP data

Figure 26 illustrates trends in unit sizes for the same fuels/technologies and countries. We omit solar and wind fuels in this figure, as these technologies are aggregated to station size in the database.[75] As is the case with station sizes, steam turbine units (coal-fired and separately presented gas-fired units) are among the largest. However, both gas-fired steam turbines and coal units have fallen out of favour

[75] Likely due to the fact that PV panels are typically measured in hundreds of watts and wind turbines in single-digit MW; inclusion of each individual panel and/or wind turbine would make the database very large.

in recent years, likely due to the reasons highlighted above. The trend in coal plant unit sizes appear to be falling in Australia and Canada, but rising in China and mixed elsewhere.

Figure 26: Unit size by fuel type

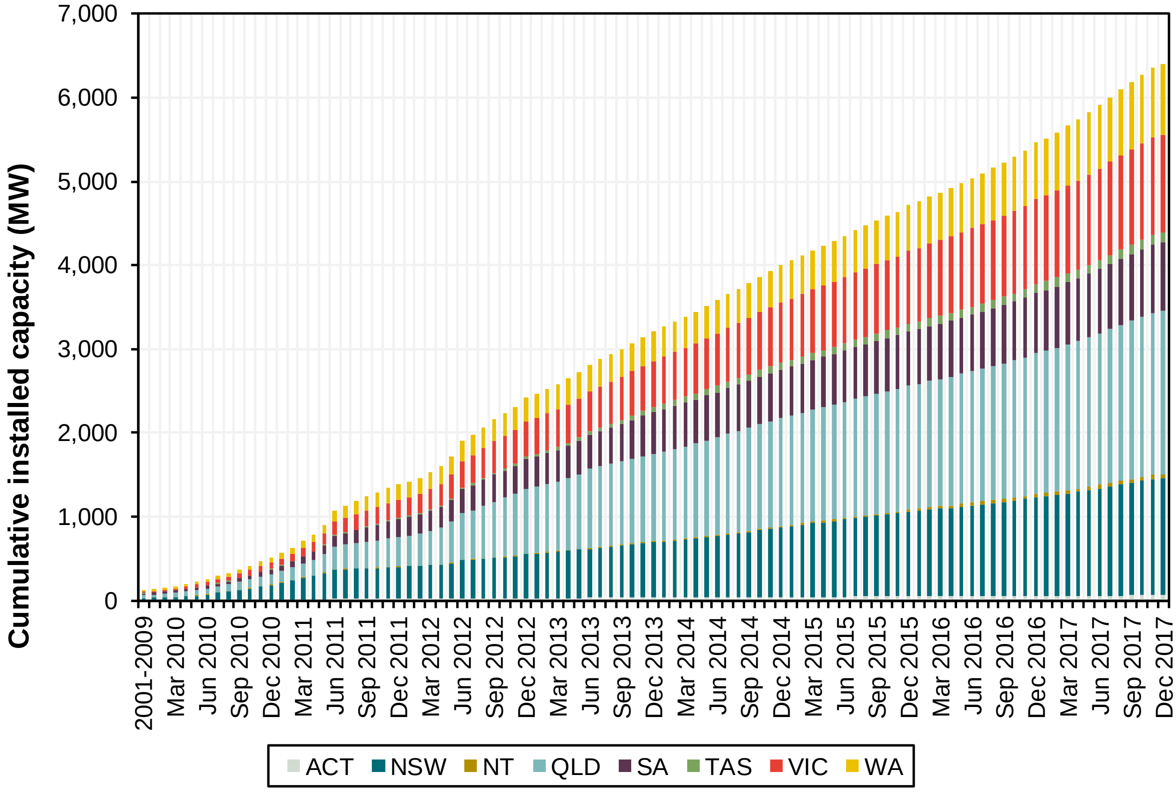


Source: Frontier Economics analysis of WEPP data

Distributed generation

From early 2010, residential rooftop solar PV installations in Australia have steadily increased in both number and size, as illustrated in **Figure 27** and **Figure 28**. The technology's popularity increased around this time due to generous federal and state government subsidies in the form of the RET, generous state-based "premium" feed-in tariffs, and underlying technology costs falling as more and more systems were installed. The financial attractiveness to customers of installing solar PV was and remains enhanced by an implicit cross-subsidy in network and retail pricing, with fixed and sunk network costs being recovered from customers through variable charges. This means that customers who install solar PV (and thereby reduce their grid-sourced consumption) are able to avoid paying for network costs that are no longer avoidable in an economic sense. The AEMC documented this issue in detail in its network pricing rule change determination.[76] Since the early 2010s, jurisdictional feed-in tariffs have become far less generous, but network cross-subsidies remain significant as cost-reflective network tariffs apply to relatively few residential customers.

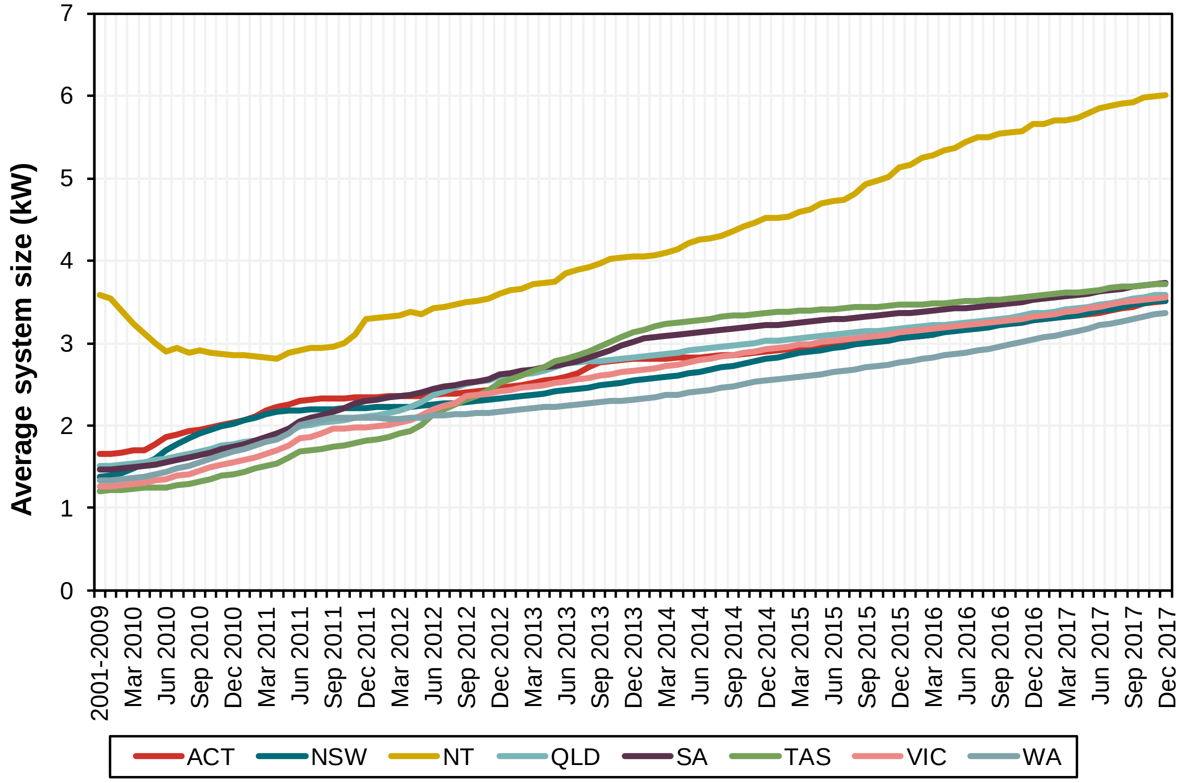
Figure 27: Rooftop PV uptake in Australia



Source: Frontier Economics analysis of CER data

[76] AEMC, *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, section 4, available at: https://www.aemc.gov.au/rule-changes/distribution-network-pricing-arrangements.

Figure 28: Average rooftop PV system size in Australia over time



Source: Frontier Economics analysis of CER data

With around 6.3GW of residential rooftop PV at the end of 2017, the technology contributes materially to meeting demand in most NEM regions. An analysis of AEMO's estimated actual rooftop PV generation data[77] suggests that from 1 October 2017 to the end of October 2018, it has generated around 7.8TWh, around 4 per cent of NEM operational demand of approximately 192TWh.

Current state of centralised generation technology in the NEM

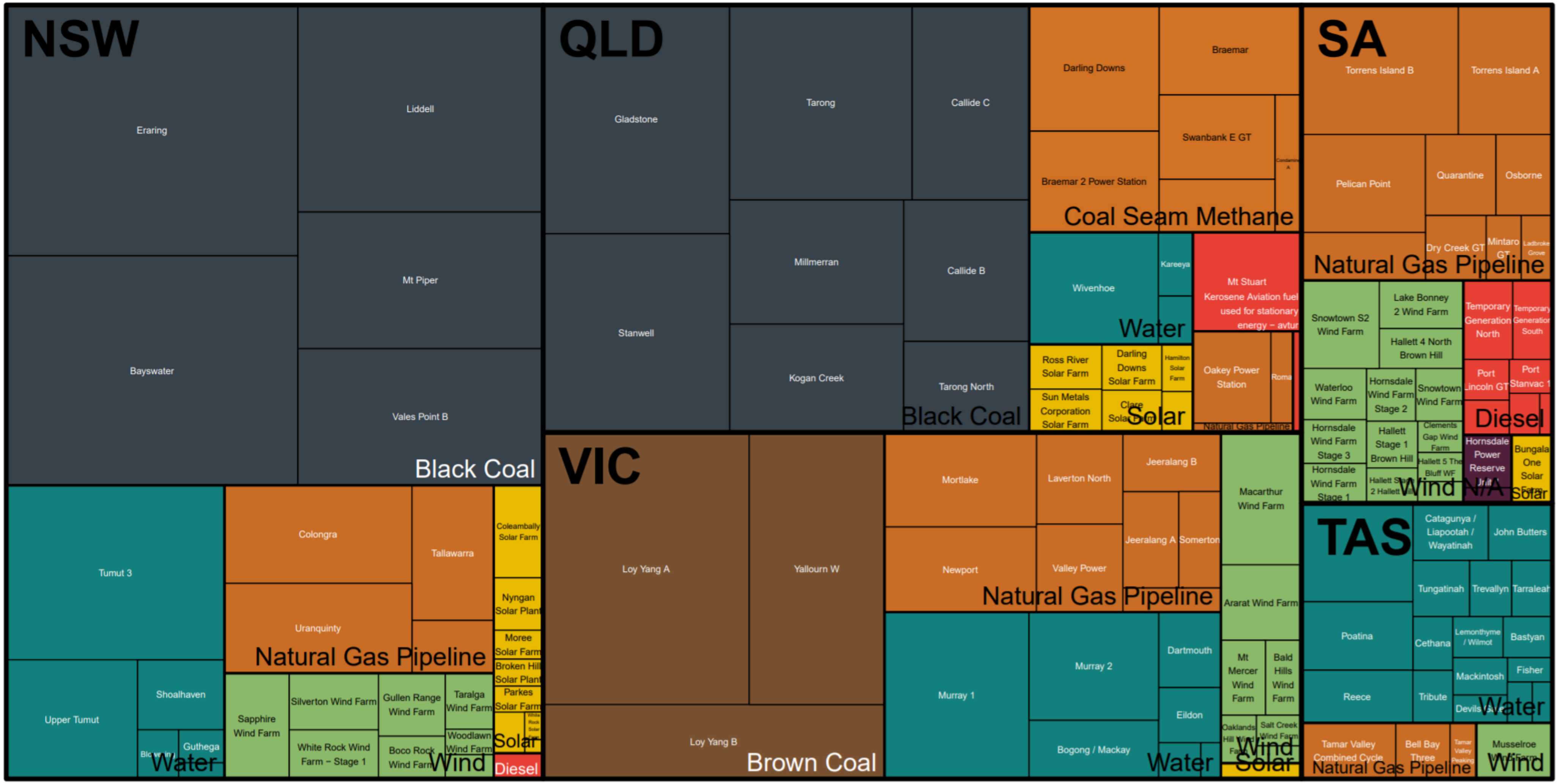
The result of the station investment path illustrated in **Figure 25** is presented in **Figure 29**, which shows the relative size of each NEM station grouped by region and fuel type. The area of each station box reflects the relative capacity of the station, and the same is true for aggregations of stations into fuel types and regions (e.g. the capacity of Queensland generation is slightly larger than Victoria, as the QLD box is slightly bigger than the VIC box). Large, coal-fired power stations in New South Wales, Queensland and (to a lesser extent, after the closure of Hazelwood) Victoria dominate the energy mix, with the remaining generation stock consisting of smaller stations fuel by gas, wind, solar and liquid fuels.

Figure 30 charts the same stations by region and fuel type on an output basis. Generally, coal and gas generators with the lowest SRMCs will operate for most of the year, higher SRMC gas generator output will fluctuate with demand, VRE is limited by available renewable resources, and high SRMC peaking power stations will only operate for a few hours in the year. The result of these operating patterns is that

[77] Available at: http://nemweb.com.au/REPORTS/ARCHIVE/ROOFTOP_PV/ACTUAL/.

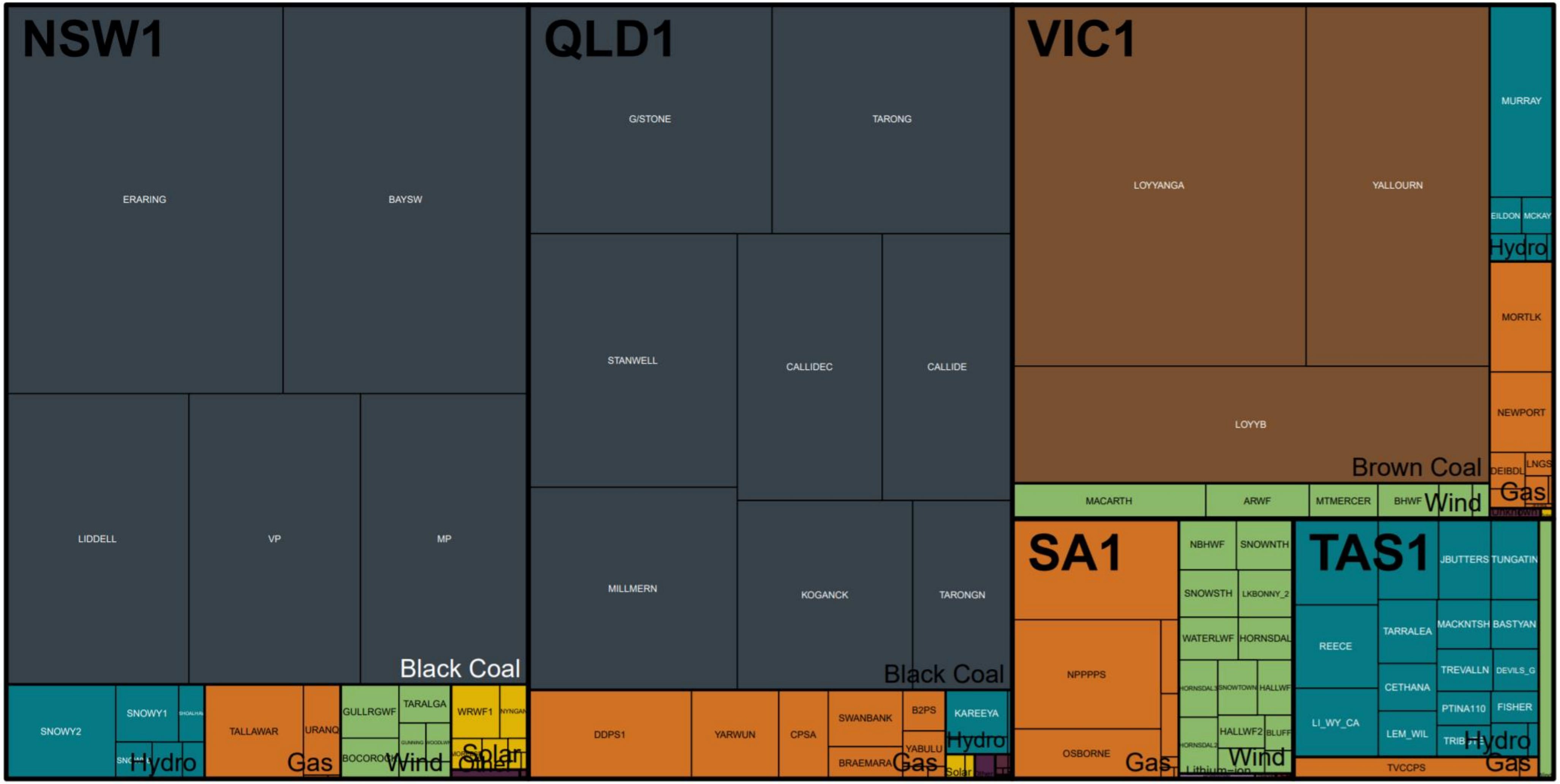
actual output in the NEM is dominated by black and brown coal from New South Wales, Queensland and Victoria.

Figure 29: NEM station capacity by region and fuel type



Source: Frontier Economics analysis of AEMO data (generation information Nov 02 2018 - https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information)

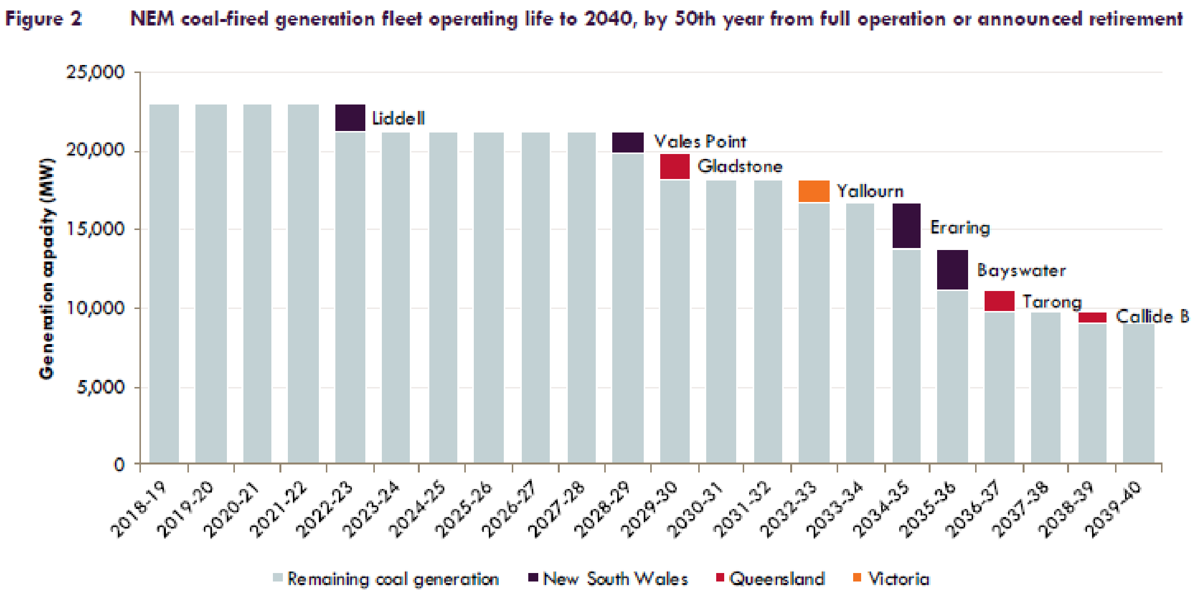
Figure 30: NEM station output by region and fuel type



Source: Frontier Economics analysis of AEMO data (MMSDM)

Despite its present dominance of the NEM plant capacity and output mix, the overall level of coal-fired generation capacity has peaked and is likely to diminish in future decades due to ongoing plant retirements **Figure 31** below shows the current stock of NEM coal-fired power stations and when they are due to be decommissioned (either when announced or after 50 years assumed). Substantial retirements are due in the 2030s, and are unlikely to be replaced with new coal. It is possible that some of these retirements (e.g. Yallourn) may be brought forward into the 2020s.

Figure 31: AEMO ISP projections of coal-fired power station retirements



Source: AEMO ISP, p.22

Part 2 – Future cost projections

CO2CRC et al, Australian Power Generation Technology Report (2015)

While the cost data in the CO2CRC et al (2015) report[78] were considered "significantly out of date" by the CSIRO in its 2017 update (see below), the CO2CRC et al (2015) report is a much more detailed document than the 2017 update and contains some useful information on unit sizes and economies of scale, particularly for renewable plant of different technologies. In particular, it highlights that renewable generators are typically available in much smaller unit sizes than traditional generators.[79]

- Wind turbines investigated in the study consist of 3 MW turbines,[80] with farm sizes of 50 MW and 200 MW – exhibiting fairly modest economies of scale:[81]
  - Capital cost (sent-out):
    - 50 MW: $2,550 / kW
    - 200 MW: $2,450 / kW
  - Operating and maintenance (O&M) cost (per annum):
    - 50 MW: $60 / kW
    - 200 MW: $55 / kW
- Solar PV is evaluated at residential (5 kW), commercial (100 kW) and utility-scale (10 MW and 50 MW) sizes, with utility-scale plant assessed at fixed, single-axis and dual-axis mounts – also exhibiting limited economies of scale:[82]
  - For fixed module mounting:
    - Capital cost (sent-out):
      - 5 kW: $2,100 / kW
      - 100 kW: $1,950/ kW
      - 10 MW: $2,400 / kW
      - 50 MW: $2,300 / kW
    - O&M cost (per annum):
      - 5 kW: $30 / kW
      - 100 kW: $30 / kW
      - 10 MW: $30 / kW
      - 50 MW: $25 / kW

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78 Wiley, D., Neal, P., Ho, M. 2015, Fimbres Weihs, G., *Australian Power Generation Technology Report*, CO2CRC, CSIRO, ARENA, Office of the Chief Economist (Federal Department of Industry and Science) and anlecr&d (CO2CRC et al (2015)).

79 CO2CRC et al (2015), p.17.

80 The CO2CRC et al report notes that average size of onshore wind turbines being installed continues to increase (p.49). While the report anticipates that offshore turbines will increase in capacity to 10-20 MW per turbine over time, it notes that onshore turbines are expected to be limited to 3-5 MW due to logistical and construction requirements (p.53). The report notes that, "Offshore wind has been developed at commercial scale globally in shallow waters. No resource maps have been developed for offshore wind in Australia. This is in part due to the narrowness of the continental shelf." (p.232)

81 CO2CRC et al (2015), p.115.

82 CO2CRC et al (2015), p.234.

- For utility-scale single-axis module mounting (which offers higher capacity factors):
  - Capital cost (sent-out):
    - 10 MW: $2,850 / kW
    - 50 MW: $2,700 / kW
  - O&M cost (per annum):
    - 10 MW: $40 / kW
    - 50 MW: $35 / kW
- For utility-scale dual-axis module mounting (which offers the highest capacity factors):
  - Capital cost (sent-out):
    - 10 MW: $3,600 / kW
    - 50 MW: $3,400 / kW
  - O&M cost (per annum):
    - 10 MW: $45 / kW
    - 50 MW: $40 / kW

- Solar thermal is investigated as a single 125 MW plant with 6 hours of direct two-tank molten storage.[83]
- Nuclear plant is investigated at a 1,100 MW unit size.[84]
- Baseload fossil fuel unit sizes are generally assumed to be no greater than 500 MW, irrespective of the specific technology (pulverised coal, integrated gasification combined cycle and natural gas combined cycle). However, ultra-supercritical pulverised coal is included in the study at 650 MW for comparison purposes.[85]

CSIRO: Hayward & Graham (2017)

More recent research produced by the CSIRO highlights the falling costs of new generation technologies.[86]

Hayward & Graham (2017) developed cost projections for a range of both conventional and new technologies out to 2050 taking into account 'learning effects' – which reduce deployment costs – of the following nature:

- Rapid learning during the early stages of a new technology's development
- Declining rates of learning as the technology increases its market share – due to established engineering and thermodynamic limits on the size of strength of components or theoretical maximum energy conversion efficiency.
- Except for solar photovoltaic generation and battery storage – which "do not appear to have a strongly settled set of underlying material components".[87] For these technologies, Hayward &

83 CO2CRC et al (2015), p.233.

84 CO2CRC et al (2015), p.236.

85 CO2CRC et al (2015), p.225.

86 Hayward, J.A. and Graham, P.W. 2017, *Electricity generation technology cost projections: 2017-2050*, CSIRO, Australia (Hayward & Graham (2017)).

87 Hayward & Graham (2017), pp.5-6, says, "While silicon panels are currently the dominant solar photovoltaic technology, there are a number of alternative materials being explored where significant progress is being made in achieving efficient energy

Graham (2017) apply their high historically observed learning rate indefinitely: "In practice, this means these technologies can achieve steeper cost reduction curves for longer than other technologies."[88]

- No learning-based cost reductions are applied to mature technologies, but a small fixed annual decline is applied across their cost inputs to reflect general productivity growth.

Hayward & Graham (2017) develop cost projects based on two scenarios:

- 2 degrees' warming (formerly 450 ppm); and
- 4 degrees' warming (formerly 550 ppm).

In the 2 degrees scenario, stronger policy action results in faster deployment and learning-based cost reductions in carbon capture and storage (CCS). However, CCS is generally deployed at a lower level than in the CSIRO's 2015 projections due to the unexpectedly large fall in projected renewable costs – particularly rooftop solar PV and solar thermal – since 2015. The new assumption about ongoing learning for solar PV along with cost reductions observed since 2015 contributed to this outcome. The solar thermal cost reductions were informed by the 150 MW South Australian Aurora project due for completion in 2020, which helped to 'restore confidence' in solar thermal projections after initial optimistic cost projections were disappointed due to the diversion of investment funds towards solar PV and wind. Wind also experienced some cost reductions compared to the 2015 projections.

Battery cost projections are largely derived from the deployment and learning effects produced by a separate transport model. Cost projections have nearly halved since the projections incorporated in the ENA Transformation Roadmap. However, the 'balance of plant' costs remain very significant.

While making a number of caveats around their calculation and use, Hayward & Graham (2017) publish conventional levelised cost of energy estimates to illustrate the effect of changes in projected capital costs since 2015. They go on to refer to other modelling which shows that the need for the deployment of intermittent renewable plant to be complemented by 'firming' capacity commences as the variable renewable share in a market rises beyond 40 per cent. From 40 to 60 per cent renewable capacity share, the modelling favoured installing batteries as a complementary technology, whereas 60 per cent, open-cycle gas turbines (OCGT) were required. By the time 90 per cent variable renewable generation is reached in 2050, the following approximate complementary capacity was required for each kW of variable renewable plant:

- 0.75 kW of batteries and synchronous condensers
- 0.4 kW of flexible dispatchable capacity (e.g. OCGT).

By 90 per cent variable renewable share, wind had suffered a 17 per cent reduction in capacity factor and solar PV had suffered a 39 per cent reduction due to the need to 'spill' excess energy production. They note that, "However, the increasing losses to the capacity factor does not significantly increase the total cost of generation because, over time, the cost of capital has also fallen to offset this effect."

While this research does not directly discuss declining economies of scale and lumpiness, it can be inferred from the inherent nature of rooftop solar PV and the relatively small sizes of wind and solar thermal plant.

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conversion and in different systems for installing the solar conversion system (Jacoby, 2016) (Fraunhofer ISE, 2015). This could mean improvements not only in the panel but in the installation and balance of system costs. Similarly, alternative battery chemistries and configurations also continue to be explored with no obvious limit on what might be achieved (Miller, 2017)."

[88] Hayward & Graham (2017), p.6.

Figure 32: Comparison of 2017 4-degrees and 2015 550ppm scenario costs, 2017 $A sent-out basis

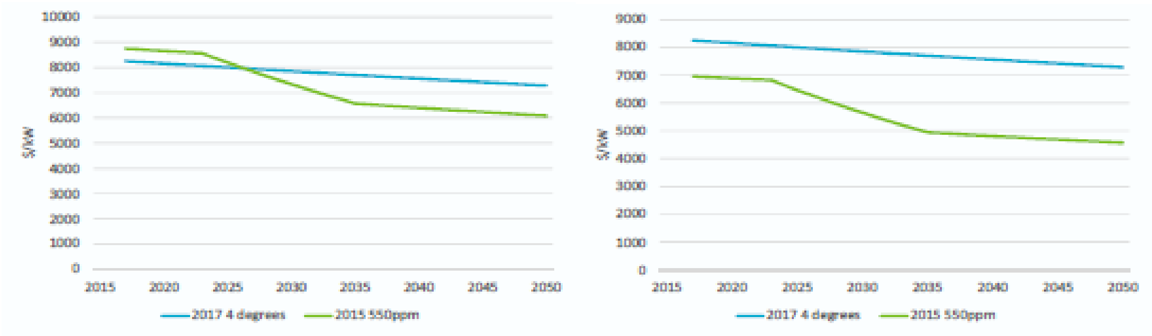


Figure 3-1: Brown coal with CCS (left) and black coal with CCS (right)

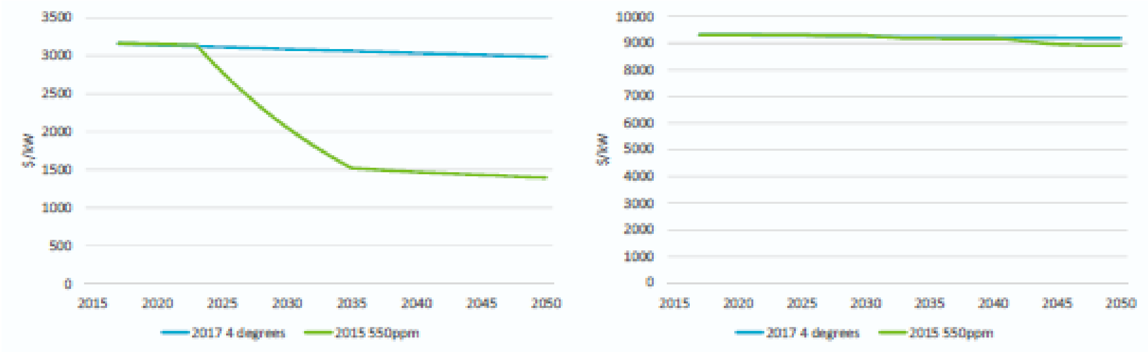


Figure 3-2: Gas with CCS (left) and nuclear (right)

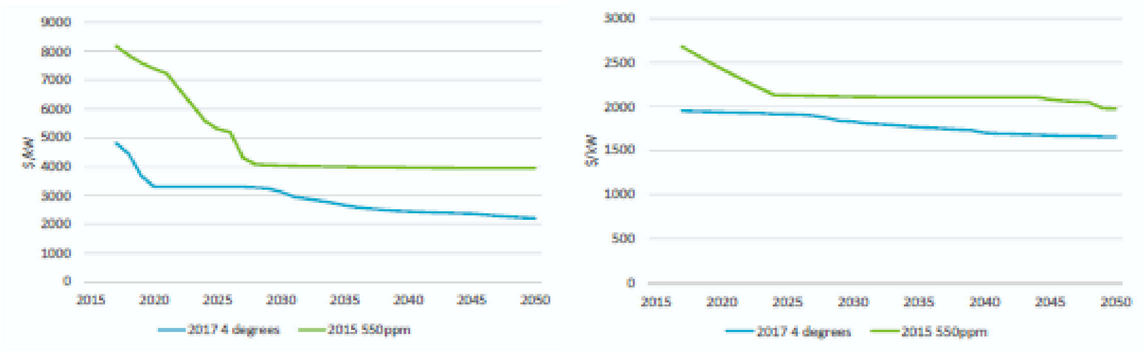


Figure 3-3: Solar thermal with 6 hours storage (left) and wind (right)

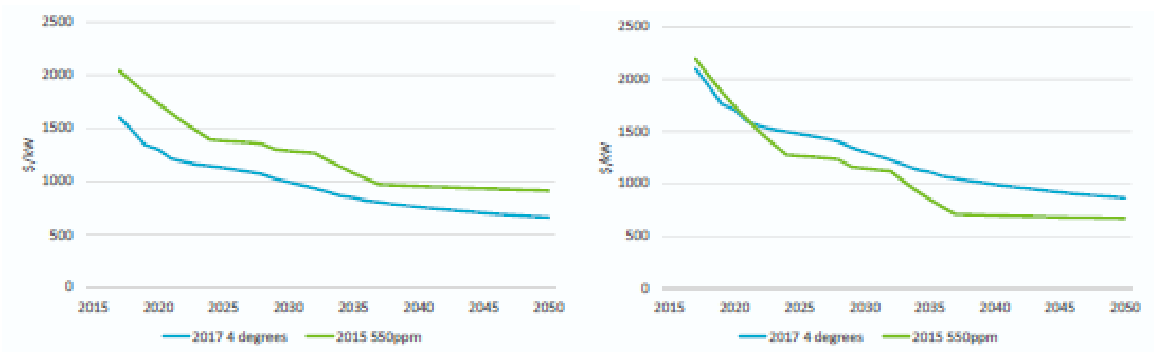


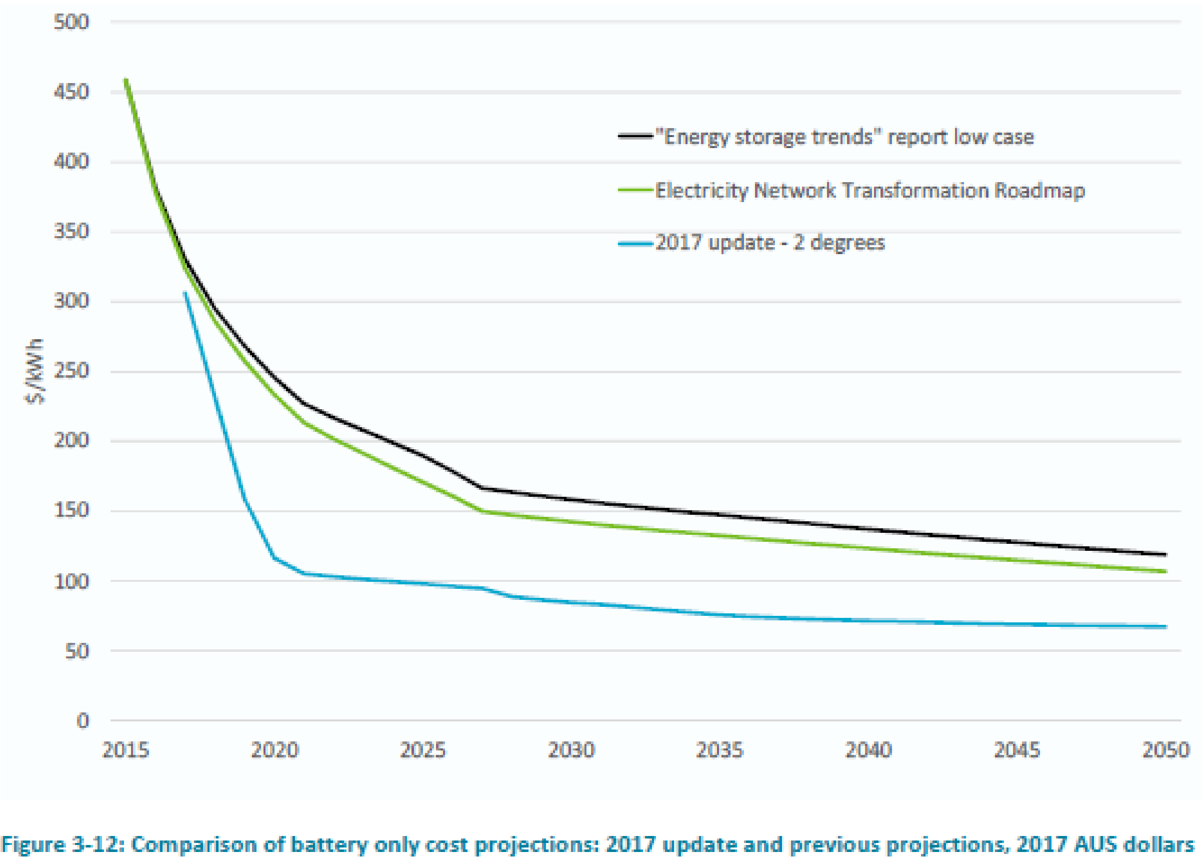
Figure 3-4: Rooftop solar photovoltaics (left) and large scale solar photovoltaics (right)

Source: Hayward & Graham (2017), p.9.

Figure 33: Comparison of 2017 2-degrees and 2015 450ppm scenario costs, 2017 $A sent-out basis

Source: Hayward & Graham (2017), p.10.

Figure 34: Battery-only cost projections: 2017 update and previous projections, 2017 $A



Source: Hayward & Graham (2017), p.14.

Figure 35: Previous CSIRO and other publicly available electricity generation technology cost projections for 2030

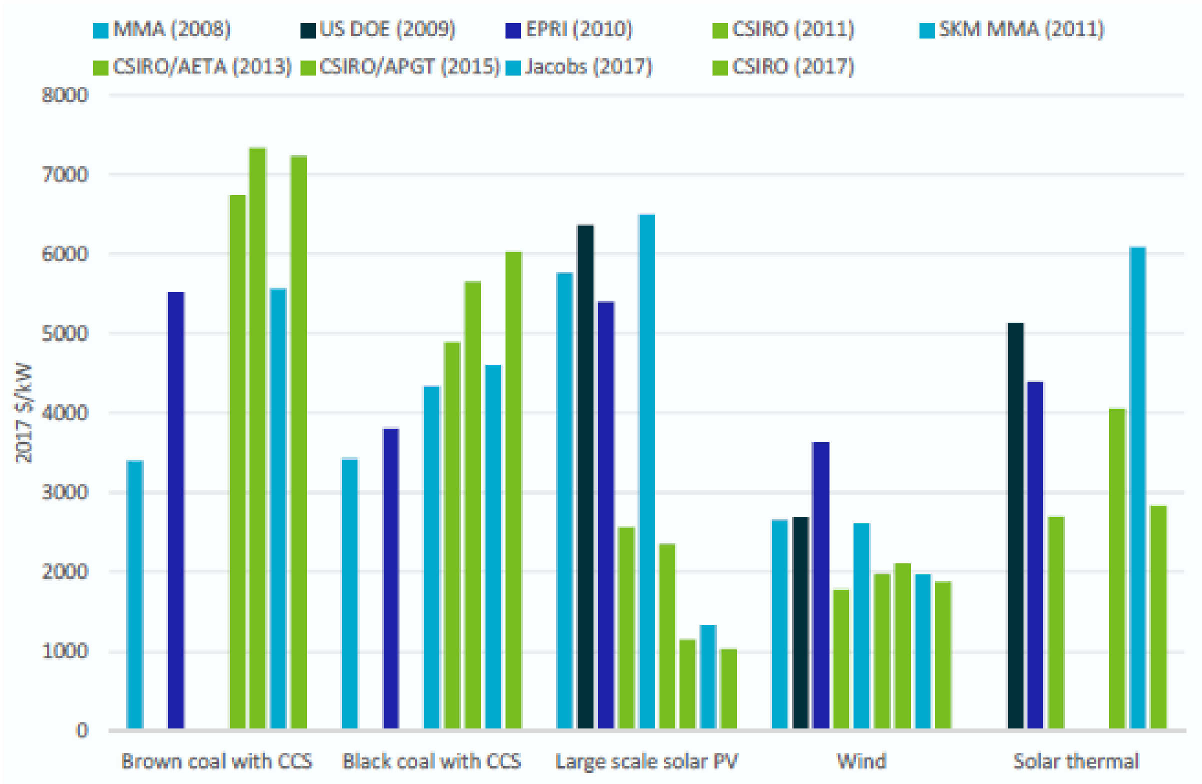


Figure 3-13: Previous CSIRO and other publicly available electricity generation technology cost projections for 2030

Notes: All CSIRO projections are shown in green with earliest starting on the left where available. The 2015 APGT was written by EPRI with cost projections provided by CSIRO. Similarly, AETA was written by the Bureau of Resources and Energy Economics and consultants. MMA, SKM MMA and Jacobs represent a reasonably continuous projections team with changes to their trading name. Consequently their projections are all shown in blue with earliest projections starting on the left where available.

Source: Hayward & Graham (2017), p.16.

Figure 36: Conventional levelised cost of electricity estimates

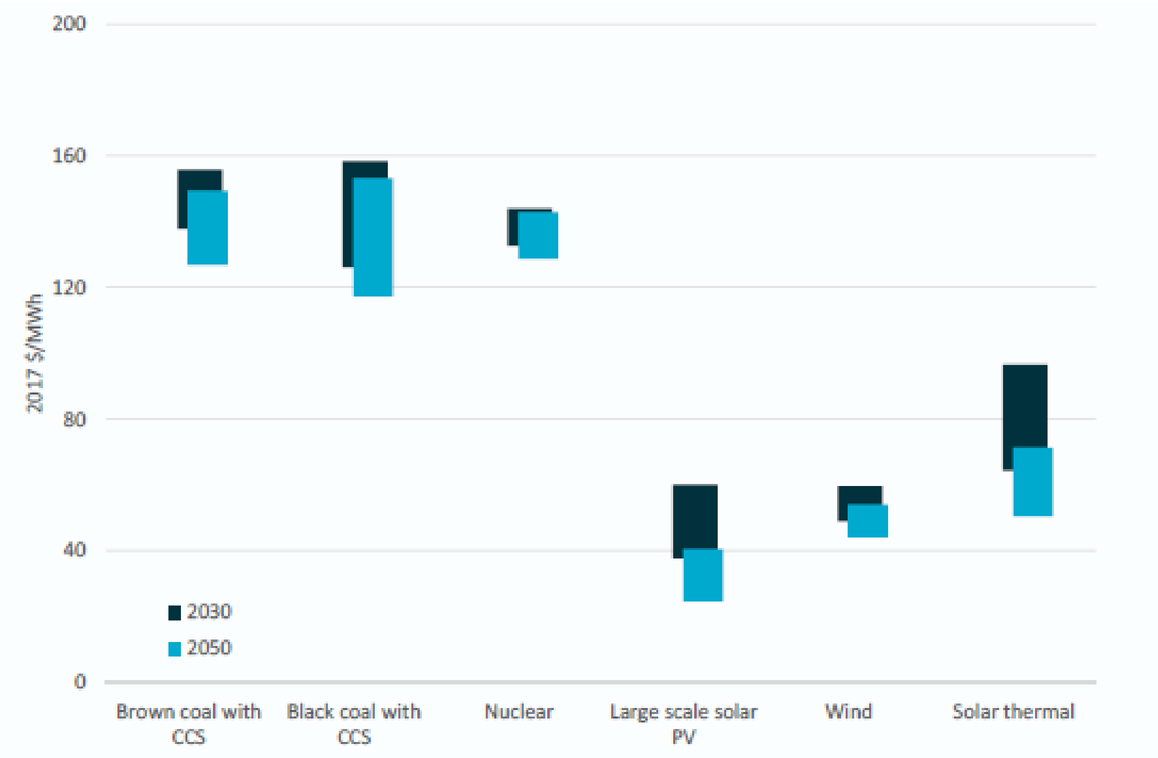


Figure 4-1: Conventional LCOE estimates for selected technologies

Table 4-1: High and low values for key LCOE assumptions

	Capacity factor (%)		O&M 2050 ($/MWh)		Fuel 2050 ($/MWh)	
	Low	High	Low	High	Low	High
Brown coal with CCS	85	85	17	21	15	25
Black coal with CCS	85	85	14	17	25	49
Nuclear	85	85	12	15	11	22
Large scale solar PV	19	32	5	6	0	0
Wind	35	42	6	7	0	0
Solar thermal	40	55	12	17	0	0

Source: Hayward & Graham (2017), p.18.

CSIRO: Graham et al (2018)

The CSIRO recently produced a report providing projections for small-scale embedded technologies, focussing on solar PV panels, batteries and electric vehicles.[89]

This report models three scenarios – Moderate, Slow and Fast – with solar PV and battery (and balance of plant or BOP) cost assumptions for the Moderate scenario largely drawing from the 4 degrees warming scenario in Hayward & Graham (2017). Charts representing both technologies' costs under the three scenarios are reproduced below.

Figure 37: Assumed solar PV capital costs

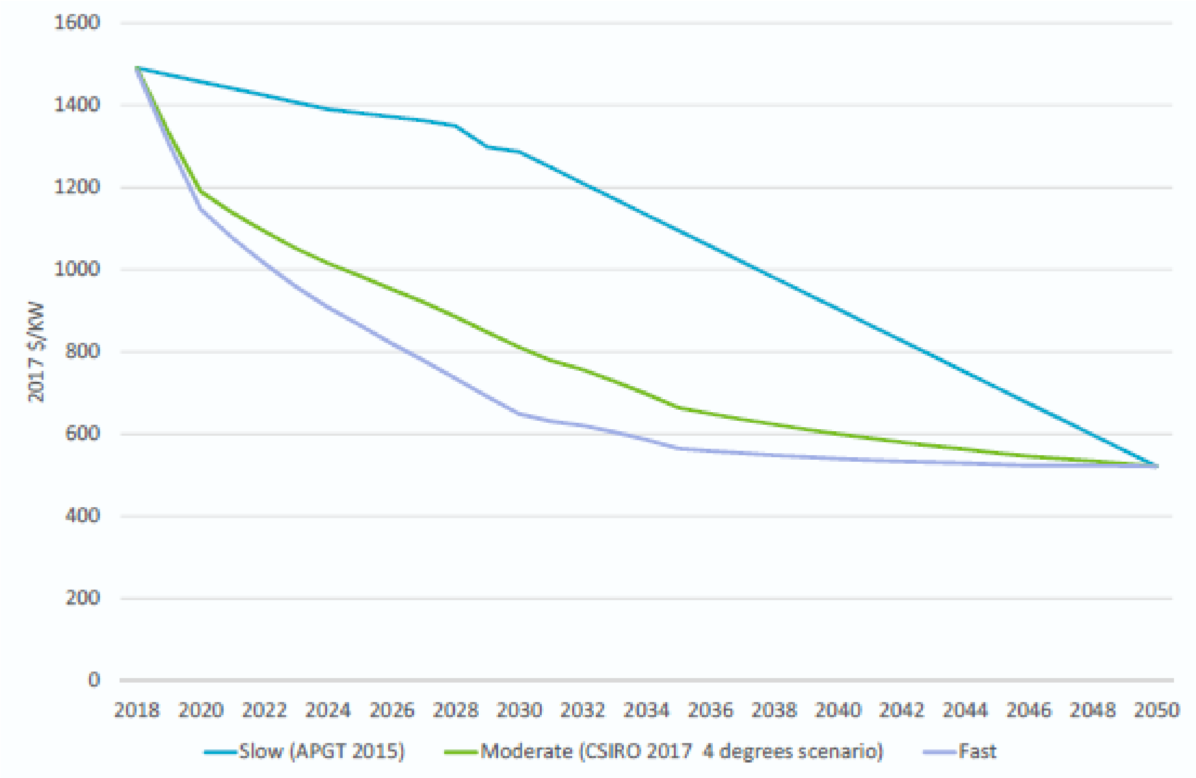


Figure 4-1: Assumed capital costs for rooftop and small-scale solar installations by scenario

Source: Graham et al (2018), p.23.

89 Graham P.W., Wang D., Braslavsky, J., and Reedman L.J. 2018. *Projections for small-scale embedded technologies, Report for AEMO*, CSIRO, Australia (Graham et al (2018)). The report was published in June 2018.

Figure 38: Assumed battery and BOP capital costs

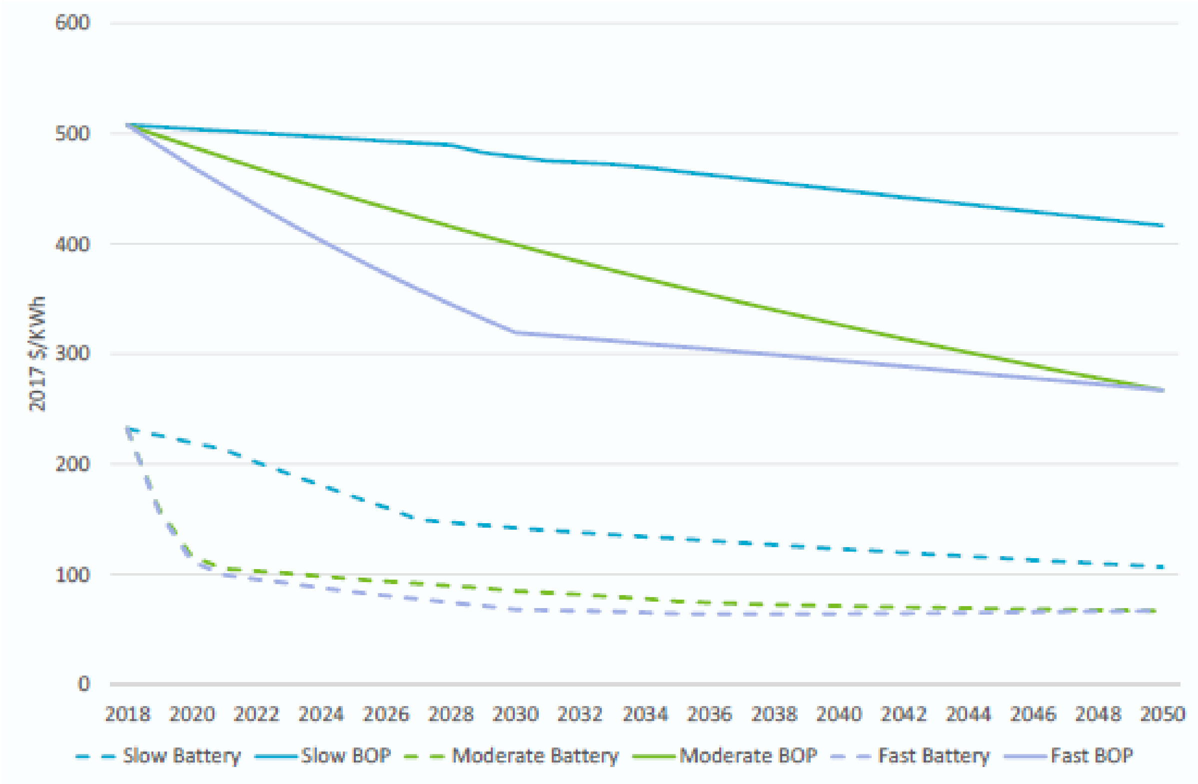


Figure 4-2: Assumed capital costs for battery storage installations by scenario

Source: Graham et al (2018), p.24.

Other key assumptions made in the report are:

- Relevant government subsidy policies for small-scale renewables are the Small-scale Renewable Energy Scheme (SRES) and the Victorian and Queensland Renewable Energy Targets (VRET and QRET). Feed-in tariffs are assumed to continue to be based on the wholesale cost of power.[90]
- Smart tariff structures gradually apply to a larger proportion of customers. In the Moderate scenario, 25 per cent of residential customers face smart tariffs by 2030 and 50 per cent by 2050.Customers facing smart tariffs are assumed to optimise battery usage to minimise grid usage at peak times.[91]

The modelling in the report does not appear to incorporate any technical 'static' limits on solar PV exports to the grid.

As a result, Graham et al (2018) came up with national and jurisdictional projections for the adoption of the following technologies across three scenarios:

- Residential rooftop solar PV
- Commercial rooftop solar PV (10 kW to 100 kW)
- Commercial solar PV (above 100 kW) – behaving as non-scheduled generation below 30 MW
- Residential batteries

90 Graham et al (2018), pp.19-20.

91 Graham et al (2018), pp.28-30.

- Commercial batteries
- Standalone power systems (SAPS) and
- Electric vehicles

The aggregate size of commercial batteries, and numbers of SAPSs and EVs are expected to be relatively low over the next decade.

To the extent small-scale embedded technologies are adopted, and the manner in which adoption occurs, is likely to have implications for the ability of generators in the wholesale market to influence prices by withholding output. This is discussed in chapter 5 above.

Part 3 – ISP projections

Background to the ISP

Following from the South Australian system black event of 26 September 2016,[92] the 2017 Finkel Review commissioned by the COAG Energy Council recommended that AEMO should have:[93]

> …a stronger role in planning the future transmission network, including through the development of a NEM-wide integrated grid plan to inform future investment decisions. Significant investment decisions on interconnection between states should be made from a NEM-wide perspective, and in the context of a more distributed and complex energy system.

In response to this recommendation, AEMO published its initial ISP in July 2018. The ISP is a cost-based engineering optimisation plan that forecasts the overall transmission system requirements for the NEM over the next 20 years. The ISP takes a range of cost inputs combined with system security and reliability considerations, expressed Commonwealth and State Government policies, to identify transmission investments that will minimise system costs in a number of scenarios. In the ISP's 'Neutral' planning scenario, the lowest cost replacement for this retiring capacity and energy is expected to involve a portfolio that includes solar (28GW), wind (10.5 GW) and storage (17 GW and 90 GWh), complemented by 500 MW of flexible gas plant and transmission investment.[94]

Transmission projections

The ISP recommends a large number of transmission investments in three tranches, depending on how urgent AEMO considers them to be – these tranches are described as follows:

- **Group 1: Near-term construction to maximise economic use of existing resources** – for immediate action to:
  - Increase transfer capacity between New South Wales, Queensland, and Victoria by 170-460 MW.
  - Reduce congestion for existing and committed renewable energy developments in western and north-western Victoria.
  - Remedy system strength in South Australia.

  Cost: $450-650 million

[92] See: https://www.aemo.com.au/Media-Centre/AEMO-publishes-final-report-into-the-South-Australian-state-wide-power-outage.

[93] Finkel Review, Recommendation 5.1, p.124.

[94] ISP, p.5.

Group 2: Developments in the medium term to enhance trade between regions, provide access to storage, and support extensive development of 'renewable energy zones' (REZs) – to initiate now for implementation by the mid-2020s to:

- Establish new transfer capacity between New South Wales and South Australia of 750 MW (RiverLink).
- Increase transfer capacity between Victoria and South Australia by 100 MW.
- Increase transfer capacity between Queensland and New South Wales by a further 378 MW (QNI).
- Efficiently connect renewable energy sources through maximising the use of the existing network and route selection of the above developments.
- Coordinate DER in South Australia.

Group 3: Longer-term developments to support REZs and system reliability and security – for the mid-2030s and beyond.

Generation projections

AEMO's ISP generation plant projections were based on a range of modelling assumptions, including for generator build costs. According to the ISP, build cost assumptions were derived from Hayward & Graham (2017), coupled with AEMO internal analysis.[95] Accordingly, it is unsurprising that the ISP projections tell a similar story to the CSIRO analysis. For the sake of completeness, the ISP's build cost projections to 2029-30 for the 'Neutral' scenario are reproduced in **Figure 39** below.[96]

Figure 40 reproduces Figure 10 from the ISP, which shows the relative changes in installed capacity in the Neutral planning scenario relative to the present generation mix over the next 20 years. It highlights the growth in both rooftop PV and utility solar (solar thermal), as well as the ongoing growth of wind, and the beginnings of significant investment in distributed and utility-level storage.

95 AEMO ISP, Table 2, p.27.

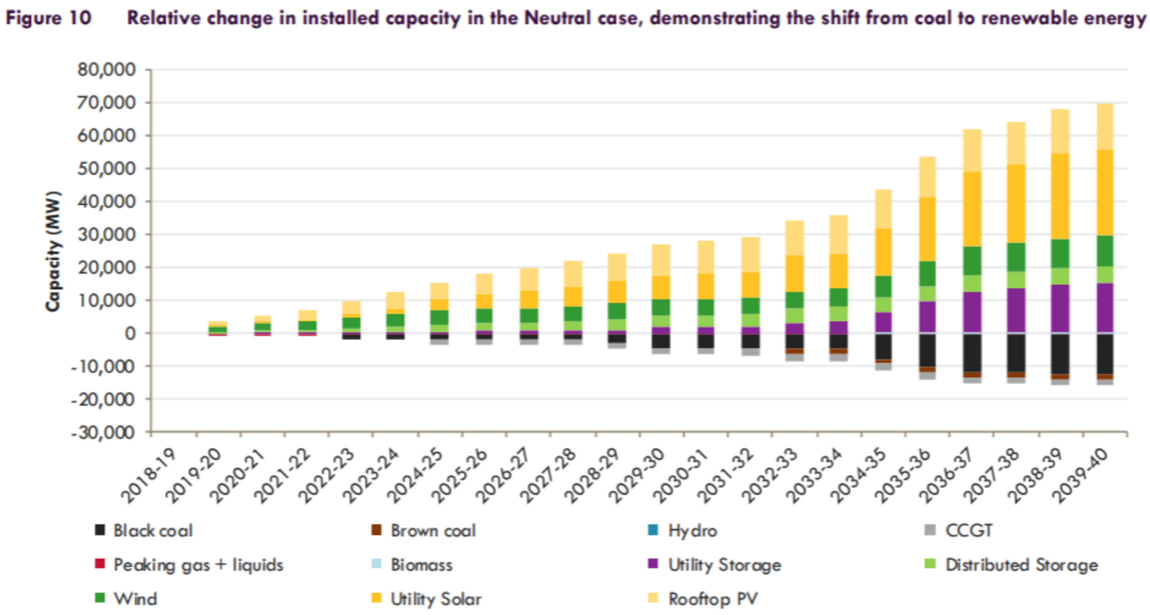
96 AEMO, *2018 ISP Assumptions workbook*, 17 July 2018, 'Build cost' tab, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-database

Figure 39: AEMO ISP – Neutral scenario – build costs ($/kW) real 2017 dollars

Neutral	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Biomass	$ 3,779.15	$ 3,770.82	$ 3,757.65	$ 3,755.92	$ 3,752.78	$ 3,752.78	$ 3,752.78	$ 3,752.78	$ 3,752.78	$ 3,752.78	$ 3,752.78	$ 3,752.78	$ 3,752.78
CCGT	$ 1,500.68	$ 1,500.66	$ 1,500.66	$ 1,500.41	$ 1,500.30	$ 1,499.99	$ 1,499.69	$ 1,499.39	$ 1,499.11	$ 1,498.46	$ 1,497.45	$ 1,496.49	$ 1,495.56
OCGT	$ 1,019.61	$ 1,014.51	$ 1,009.44	$ 1,004.39	$ 999.37	$ 994.37	$ 989.40	$ 984.45	$ 979.53	$ 974.63	$ 969.76	$ 964.91	$ 960.09
Single-axis Tracking Solar PV2	$ 1,952.05	$ 1,733.25	$ 1,634.67	$ 1,492.50	$ 1,421.39	$ 1,363.01	$ 1,316.62	$ 1,270.06	$ 1,228.59	$ 1,183.76	$ 1,148.26	$ 1,081.55	$ 1,033.69
Solar Thermal Central Receiver (6 hrs storage)	$ 4,434.41	$ 3,677.62	$ 3,299.20	$ 3,299.20	$ 3,299.20	$ 3,299.20	$ 3,299.20	$ 3,299.20	$ 3,296.30	$ 3,137.48	$ 3,031.77	$ 2,905.32	$ 2,835.99
Wind	$ 1,945.06	$ 1,940.42	$ 1,933.93	$ 1,924.78	$ 1,921.10	$ 1,908.58	$ 1,901.27	$ 1,899.67	$ 1,899.10	$ 1,899.01	$ 1,898.92	$ 1,898.77	$ 1,875.96
Pumped Hydro (6hrs storage)	$ 1,386.11	$ 1,379.18	$ 1,372.29	$ 1,365.42	$ 1,358.60	$ 1,351.80	$ 1,345.04	$ 1,338.32	$ 1,331.63	$ 1,324.97	$ 1,318.35	$ 1,311.75	$ 1,305.19
Large Scale Battery Storage (2hrs storage)	$ 1,480.18	$ 1,313.14	$ 1,208.39	$ 1,166.77	$ 1,143.42	$ 1,120.72	$ 1,099.36	$ 1,078.22	$ 1,057.30	$ 1,036.78	$ 1,008.10	$ 986.98	$ 967.01
Black Coal (HELE)	$ 3,268.42	$ 3,263.89	$ 3,249.43	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50

Source: AEMO, 2018 Integrated System Plan Modelling Assumptions workbook, 'Build cost' tab.

Figure 40: ISP projections of changes in plant mix



Source: AEMO ISP, p.38.

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